Great Bay Power Corporation

1995
Annual Report

GREAT BAY POWER CORPORATION

To the Shareholders of Great Bay Power Corporation:

Great Bay has made good progress in 1995 the first full fiscal year following its emergence from Chapter 11 in November 1994. Our goal for the year was to stabilize the financial condition of the Company and to lay the groundwork for future growth. We believe we have succeeded.

While the Company does not have operational responsibility for the Seabrook Plant, the Company's results are highly dependent upon the performance of the plant. During 1995, the capacity factor for the Seabrook Plant was 83.2%. This capacity factor includes a scheduled refueling outage which lasted 37.5 days — the shortest refueling outage in the plant's history. Excluding the scheduled refueling outage, the plant's capacity factor for the year was 92.7% — a very respectable operating performance. The Seabrook Plant is moving from an 18 month to a 24 month refueling cycle, with the next refueling outage currently scheduled to occur during the Summer of 1997.

Operating revenues for the year increased 43% to $24.5 million. This was primarily the result of the 1995 Seabrook Plant capacity factor of 83.2% as compared to a 1994 capacity factor of 61.6%. The Company also experienced an increase of approximately 6% in the sales price per kWh, from 2.27 cents per kWh in 1994 to 2.41 cents per kWh in 1995. Despite this increase, however, revenues from sales at current spot market prices are not sufficient to cover Great Bay's operating expenses.

Great Bay has a strong balance sheet, with no long term debt and approximately $16.5 million in cash or cash equivalents (or $2.06 per share) at the end of 1995. We are acutely aware that in a deregulated commodity business a company must control its costs or face extinction. We believe that our cost structure on a cents per kWh basis is one of the lowest in the industry. We are committed to maintaining this low cost structure and are continuously seeking ways to reduce our costs and enhance our competitive position.

We took several actions in 1995 which we believe will increase our competitive position in 1996 and beyond. In an effort to emerge from Chapter 11 as expeditiously as possible, the Company had sourced out all of its administrative functions, including management support, accounting, bookkeeping, budgeting and regulatory compliance. At the beginning of 1996, the Company began to take these functions in-house to maintain control over our books and records and to cuts costs. We expect to complete this transition by the end of the second quarter of 1996 and we expect that this move will result in considerable cost savings for the Company in 1996.

In addition, in November 1995 the Company entered into a strategic marketing and back-up power arrangement with PECO Energy Company which we believe will enhance our revenue. PECO has a strong power marketing presence in the Pennsylvania, New Jersey, Maryland region. We felt that by placing our marketing effort with a non-New England utility we would avoid potential conflicts and best capitalize on our position as an alternative supplier in New England. Under the marketing agreement, which commenced on January 1, 1996, PECO acts as the Company's exclusive marketing agent for its approximately 130 megawatts of uncommitted capacity. PECO has also agreed to provide back-up power to customers during scheduled and unscheduled outages at the Seabrook Plant. With this commitment, the Company is now able to offer a different product to customers: firm, all requirements service. We believe that this will result in the Company receiving higher prices for its power since firm power generally commands a modest premium over non-firm, unit power.

We felt it was important that our marketing agent's interests be aligned with our own, thus PECO is compensated based solely upon a revenue sharing formula. If PECO is successful in obtaining higher prices, everyone realizes greater revenues. Our interests are even further aligned because PECO purchased from the Company a warrant for $1 million which gives PECO the right to acquire 4.99% of the Company's common stock at a price of at least $9.75 per share. The warrant expires on September 30, 1996, as long as the Seabrook Plant continues to operate well until that time. If PECO exercises the warrant, the $1 million purchase price will be credited towards the exercise price. We are very excited about this new strategic relationship with PECO. They are very good at what they do, namely bulk trading of wholesale power, and we expect that the Company will benefit from this relationship.

Finally, a comment on the state of deregulation of the electric utility industry. In 1994, the question was *whether or not* the electric industry would deregulate. In 1995, we believe that there has been a general consensus reached that deregulation will occur and the only question is *when*. Especially here in New England, several states seem to be in a race to see who can reach competition first. While there are sure to be fits and starts along the way, and while it is impossible to predict the final form deregulation will take, we expect that the old monopoly structure will crumble as increased competition is introduced into the marketplace. We are hopeful that increased competition means additional sales opportunities for the Company. Where there is change, there is opportunity. We will continue to monitor the fundamental changes occurring in the electric utility industry with the hope of identifying and seizing profitable opportunities as they present themselves.

John A. Tillinghast
President and CEO

March 1996

This Annual Report contains forward-looking statements. For this purpose, any statements contained herein which are not statements of historical fact may be deemed to be forward-looking statements. Without limiting the foregoing, the words "believes," "anticipates," "plans," "expects" and similar expressions are intended to identify forward-looking statements. There are a number of important factors that could cause the Company's actual results to differ materially from those indicated by the forward-looking statements. These factors include, without limitation, those set forth under the caption "Certain Factors That May Affect Future Results" in the Company's Annual Report on Form 10-K which forms a part of this Annual Report.

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1995

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 0-25748

GREAT BAY POWER CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire (State or other jurisdiction of incorporation or organization)	**02-0396811** (I.R.S. Employer Identification No.)
20 Ladd Street **Portsmouth, New Hampshire** (Address of principal executive offices)	**03801-4080** (Zip Code)

Registrant's telephone number, including area code: (603) 433-8822

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $.01 par value
(Title of class)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

As of March 13, 1996, the approximate aggregate market value of the voting stock held by non-affiliates of the registrant was $21,199,344 based on the last reported sale price of the registrant's Common Stock on the Nasdaq National Market as of the close of business on March 13, 1996. There were 7,999,948 shares of Common Stock outstanding as of March 13, 1996.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Part of Form 10-K into which incorporated
Portions of the Registrant's Proxy Statement for the 1996 Annual Meeting of Stockholders	Items 10, 11, 12 & 13 of Part III

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PART I

Item 1. *Business.*

Introduction

Great Bay Power Corporation ("Great Bay" or the "Company") is a New Hampshire public utility whose principal asset is a 12.1% joint ownership interest in the Seabrook Nuclear Power Project (the "Seabrook Project") in Seabrook, New Hampshire. The Company sells its share of the electricity output of the Seabrook Project in the wholesale electricity market, primarily in the Northeast United States. Great Bay does not have operational responsibility for the Seabrook Project. The Company's share of the Seabrook Project capacity is approximately 140 megawatts ("MW"). Great Bay currently sells all but 10 MW of its share of the Seabrook Project capacity in the short-term market.

The Seabrook Project

The Seabrook Project is located on an 896 acre site in Seabrook, New Hampshire. It is owned by the Company and nine other utility companies, consisting of Northeast Utilities and its affiliates, The United Illuminating Company, Canal Electric Company, Massachusetts Municipal Wholesale Electric Company, Montaup Electric Company, New England Power Company, New Hampshire Electric Cooperative, Inc., Taunton Municipal Lighting Plant and Hudson Light & Power Department (together with the Company, the "Participants").

Seabrook Unit 1 is a 1,150 MW nuclear-fueled steam electricity generating station. It employs a four loop, pressurized water reactor and support auxiliary systems designed by the Westinghouse Electric Company. The reactor is housed in a steel-lined reinforced concrete containment structure and a concrete containment enclosure structure. Reactor cooling water is obtained from the Atlantic Ocean through a 17,000 foot long intake tunnel and returned through a 16,500 foot long discharge tunnel. The station has a remaining expected service life of 30 years. Seabrook Unit 1 transmits its generated power to the New England 345 kilovolt transmission grid, a major network of interconnecting lines covering New England, through three separate transmission lines emanating from the station. On March 15, 1990, the Joint Owners of Seabrook Unit 1 received from the Nuclear Regulatory Commission (the "NRC") a full power operating license which authorizes operation of Seabrook Unit 1 until October 2026. Commercial operation of Seabrook Unit 1 commenced on August 19, 1990. Management believes that Seabrook Unit 1 is in good condition.

Since the Seabrook Project was originally designed to consist of two generating units, the Company also owns a 12.1% joint ownership interest in Seabrook Unit 2, to which it has assigned no value. On November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been canceled in 1984, voted to dispose of Unit 2. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. The Participants are currently considering plans regarding disposition of Seabrook Unit 2, but such plans have not yet been finalized and approved. The Company is unable to estimate the costs for which it will be responsible in connection with the disposition of Seabrook Unit 2. Because Seabrook Unit 2 was never completed or operated, costs associated with its disposition will not include any amounts for decommissioning. The Company currently pays its share of monthly expenses required to preserve and protect the value of the Seabrook Unit 2 components.

Joint Ownership of Seabrook

The Company and the other Participants are parties to an Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units dated May 1, 1973, as amended (the "JOA"). The JOA establishes the respective ownership interests of the Participants in the Seabrook Project and defines their responsibilities with respect to the ongoing operation, maintenance and decommissioning of the Seabrook Project. In general, all ongoing costs of the Seabrook Project are divided proportionately among the Participants in accordance with their ownership interests in the Seabrook Project. Each Participant is only liable for its share of the Seabrook Project's costs and not liable for any other Participant's share. The Company's joint ownership interest of 12.1% is the third largest interest among the Participants, exceeded only by the approximately 40% interest held by Northeast Utilities and its affiliates and the 17.5% interest held by The United Illuminating Company.

A Participant may sell any portion of its ownership interest to any entity that is engaged in the electric utility business in New England. Before such sale, however, such selling Participant must give certain other Participants the right of first refusal to purchase the interest on the same terms. Any Participant may transfer, free from the foregoing right of first refusal, any portion of its interest (a) to a wholly-owned subsidiary, (b) to another company in the same holding company system or a construction trust for the benefit of the transferor or another company in the same holding company system, or (c) in connection with a merger, consolidation or acquisition of the assets of such Participant.

The JOA provides for a Managing Agent to carry out the daily operational and management responsibilities of the Seabrook Project. The current Managing Agent, appointed on June 29, 1992, is North Atlantic Energy Service Corporation ("NAESCO"), a wholly-owned subsidiary of Northeast Utilities. Northeast Utilities, in conjunction with certain of its affiliates, holds the largest joint ownership interest, as described above. Certain material decisions regarding the Seabrook Project are made by an Executive Committee consisting of the chief executive officers of certain of the Participants or their designees. There are currently five members of the Executive Committee. The Executive Committee acts by majority vote of its members, although any action of the Executive Committee may be modified by vote of 51% of the ownership interests. The Company does not have a representative on the Executive Committee. Under the JOA, the appointment of the managing agent of the Seabrook Project may only be made by a majority in interest of the Participants.

Bankruptcy Proceeding and Reorganization

The Company filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the District of New Hampshire (the "Bankruptcy Court") on February 28, 1991. It conducted its business as a Debtor in Possession until November 23, 1994, at which time the Company's First Amendment to the First Modified Plan dated September 9, 1994 (the "Amended Plan") became effective and the Company emerged from Chapter 11. Financing for the Amended Plan was provided by affiliates of Omega Advisors, Inc. and by Elliott Associates, L.P. (collectively, the "Investors"). At the time the Company emerged from Chapter 11, the Investors purchased 4,800,000 shares of the Company's Common Stock for $35,000,000.

Current Business

The business of Great Bay consists of the management of its joint ownership interest in the Seabrook Project and the sale in the wholesale power market of its share of electricity produced by the Seabrook Project. Great Bay does not have operational responsibility for the Seabrook Project. To date, the Company has entered into one long-term power contract for approximately 10 MW of Great Bay's share of the Seabrook Project capacity. The Company's business strategy is to seek purchasers, either in the short-term market or pursuant to medium or long-term contracts, for its share of the Seabrook Project electricity output at prices in excess of the prices currently available in the short-term market since sales at current short-term prices result in revenues which are less than the Company's cash requirements for operations, maintenance and capital expenditures.

The Company is currently considering reorganizing into a holding company structure pursuant to which the Company would become a wholly-owned subsidiary of a holding company. Such a structure would permit the holding company to engage in business activities, through subsidia[illegible] other than the Company, from which the Company is prohibited from engaging because of its status as an Exempt Wholesale Generator ("EWG") under the Public Utility Holding Company Act of 1935. The Company is also subject to regulation by the New Hampshire Public Utilities Commission (the "NHPUC") as a New Hampshire public utility. Many transactions by the Company are subject to approval by the NHPUC. While the activities of the Company would continue to be subject to such regulation, the activities of the holding company would not be.

Marketing

The Company and PECO Energy Company ("PECO") entered into a Services Agreement dated as of November 3, 1995 (the "PECO Services Agreement"), pursuant to which PECO was appointed as the Company's exclusive agent to market and sell the Company's uncommitted portion of electricity generated by the Seabrock Project. Proceeds from the sale of the Company's electricity together with reservation fees payable by PECO to the Company will be shared between the Company and PECO in accordance with formulas set forth in the PECO Services Agreement.

The PECO Services Agreement became effective on December 31, 1995, and has an initial term of two years. The term will be automatically extended for one additional year (to December 31, 1998) if PECO exercises the PECO Warrant to purchase the Warrant Shares, described below. At any time prior to the Warrant Expiration Date (as defined below), the Company is entitled to terminate the PECO Services Agreement; however, if the PECO Services Agreement is so terminated, the Company will be required to refund to PECO the $1,000,000 purchase price for the Warrant plus interest.

At the time that the Company entered into the PECO Services Agreement, the Company and PECO entered into a Warrant Purchase Agreement, dated November 3, 1995, pursuant to which on February 15, 1996, PECO purchased a warrant (the "PECO Warrant") from the Company for $1,000,000. The PECO Warrant entitles PECO to purchase 420,000 shares of the Company's Common Stock (the "Warrant Shares") at an exercise price of the higher of (1) $9.75 per share, or (2) the highest trading price per share of the Company's Common Stock prior to the expiration date of the PECO Warrant. The $1,000,000 purchase price for the PECO Warrant will be credited toward the aggregate exercise price of the PECO Warrant upon exercise. If PECO does not exercise the PECO Warrant, the purchase price for the PECO Warrant is wholly or partially refundable only if the Company terminates the PECO Services Agreement for convenience prior to the Warrant Expiration Date or if PECO exercises certain of its rights to terminate the PECO Services Agreement. The PECO Warrant expires on September 30, 1996 (the "Warrant Expiration Date") unless extended because the Seabrook Project fails to maintain a 60% capacity factor for the first 9 months of 1996, in which case the Warrant Expiration Date will be extended until the earlier of such time as the Seabrook Project's rolling 12-month capacity factor equals or exceeds 60% or December 31, 1997.

From November 23, 1994 to December 31, 1995, UNITIL Resources, Inc. ("URI"), a wholly owned subsidiary of UNITIL Company ("UNITIL") marketed the Company's energy. The Company paid URI commissions for sales of power plus reimbursement for URI's time. The amount of the commission varied based on the length of the power sale contracts and prices obtained. For the year ended December 31, 1995, the Company paid $333,138 for services rendered pursuant to this marketing agreement with URI. The marketing agreement with URI terminated as of December 31, 1995.

The Company currently sells most of its power to utility companies located in the Northeast United States in the short-term wholesale power market. Great Bay is currently not dependent on any single customer because many utilities and marketers are willing to buy the Company's share of electricity from the Seabrook Project at substantially the same price. Prices in the short-term market are typically higher during the summer and winter because the demand for electrical power is higher during these periods in the Northeast United States. Sales of power to UNITIL Power Corporation ("UNITIL Power"), a wholly owned subsidiary of UNITIL, accounted for more than 10% of the Company's revenues during 1995. See "Power Purchase Agreements."

Power Purchase Agreements

The Company is a party to a power agreement, dated as of April 1, 1993 (the "UNITIL Power Purchase Agreement"), with UNITIL Power Corp. ("UNITIL Power"), a wholly-owned subsidiary of UNITIL, which provides for the Company to sell to UNITIL Power approximately 10 MW of power. The UNITIL Power Purchase Agreement commenced on May 1, 1993 and runs through October 31, 2010. During the first year of this term, the price of power under the UNITIL Power Purchase Agreement was 5.0 cents per kilowatt-hour ("kWh"). Thereafter, the price is subject to increase in accordance with a formula which provides for adjustments at less than the actual rate of inflation. UNITIL Power has an option to extend the UNITIL Power Purchase Agreement for an additional 12 years until 2022.

The UNITIL Power Purchase Agreement is front-end loaded whereby UNITIL Power pays higher prices, on an inflation adjusted basis, in the early years of the Agreement and lower prices in later years. The amount of the excess paid by UNITIL Power in the early years of the UNITIL Power Purchase Agreement is quantified in a "Balance Account" which increases annually to $4.1 million in 1998, then decreases annually, reaching zero in 2001. If the UNITIL Power Purchase Agreement terminates prior to its scheduled termination, and if at that time there is a positive amount in the Balance Account, the Company is obligated to refund that amount to UNITIL Power.

To secure the obligations of the Company under the UNITIL Power Purchase Agreement, including the obligation to repay to UNITIL Power the amount of the Balance Account, the UNITIL Power Purchase Agreement grants UNITIL Power a mortgage on the Company's interest in the Seabrook Project. This mortgage may be subordinated to first mortgage financing of up to a maximum amount of $80,000,000. The UNITIL Power Purchase Agreement further provides that UNITIL Power's mortgage will rank pari passu with other mortgages that may hereafter be granted by the Company to other purchasers of power from the Company to secure similar obligations, provided that (i) the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest may not exceed $80,000,000 and (ii) the combined total of all second mortgages on the Seabrook Interest may not exceed the sum of (a) $80,000,000 less the total amount of the Company's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

In addition to the UNITIL Power Purchase Agreement, the Company also has entered into an option agreement with UNITIL Power (the "Power Purchase Option Agreement") under which the Company has granted UNITIL Power the option to purchase, during the period from November 1, 1998 through October 31, 2018, approximately 15 MW of electricity at a price equal to 6.5 cents per kWh, subject to adjustment in accordance with a formula. UNITIL Power is required to exercise its option under the Power Purchase Option Agreement on or before the earlier of (i) October 31, 1996, or (ii) 30 days after the first date on which the Company is prepared to commit to sell, for a minimum of 10 years, all or any part of the last remaining 15 MW of the Company's share of power generated by the Seabrook Project. Based on the current market conditions, the Company believes that it is unlikely that UNITIL Power will exercise this option under the Power Purchase Option Agreement.

The Company has also entered into a Purchased Power Agreement, dated as of March 2, 1995 (the "Freedom Purchased Power Agreement"), with Freedom Energy Company ("Freedom Energy") pursuant to which the Company agreed to sell to Freedom Energy, subject to the satisfaction of certain material conditions precedent, up to 20 MW of power at an initial price of approximately 4.5 cents per kWh. The Freedom Purchased Power Agreement is subject to the receipt by Freedom Energy of all necessary regulatory approvals, including approval from the NHPUC to operate as a utility and to sell electricity directly to end-users and approval by the Federal Energy Regulatory Commission ("FERC") of the rates specified in the agreement. In addition, the agreement is subject to the entry by Freedom Energy into an agreement with Public Service Company of New Hampshire ("PSNH") for transmission services. The Company has the right, which it has not exercised, to terminate the Freedom Purchased Power Agreement since these conditions were not satisfied by February 28, 1996. Freedom Energy has petitioned the NHPUC for permission to sell electric power directly to end-users located in the franchise service area of PSNH, but it is not currently authorized to operate as an electric utility. The Company is unable to predict whether Freedom Energy will obtain the necessary approvals or customers to purchase electricity from the Company.

The Company is also a party to a Purchased Power Agreement, dated November 9, 1995 (the "Bangor Purchased Power Agreement"), with Bangor Hydro-Electric Company ("Bangor Hydro") pursuant to which Bangor Hydro agreed to purchase from the Company, subject to increase or reduction under certain circumstances, 10 MW of electricity during the months of January through March 1996 and for the months of November 1996 through March 1997 and November 1997 through March 1998. Pursuant to the Bangor Purchased Power Agreement, the Company also granted to Bangor Hydro an option to purchase from the

Company up to 10 MW of electricity for the months of November 1998 through March 1999 and November 1999 through March 2000.

Competition

The Company sells its share of Seabrook electricity into the wholesale electricity market in the Northeast United States. There are a large number of suppliers to this market and a surplus of capacity, resulting in intense competition. A primary source of competition comes from traditional utilities, many of which presently have excess capacity. In addition, non-utility wholesale generators of electricity, such as independent power producers ("IPPs"), Qualifying Facilities ("QFs") and EWGs, a new class of non-utility generators established by the Energy Policy Act of 1992 (the "Energy Act"), as well as power marketers and brokers, actively sell electricity in this market.

The Company may face increased competition, primarily based on price, from all the foregoing sources in the future. The Company believes that it will be able to compete effectively in the wholesale electricity market because of the current low cost of electricity generated by the Seabrook Project in comparison with existing alternative sources and the reduction of the Company's capital costs resulting from the implementation of the Chapter 11 reorganization plan. In addition, the Company believes that the commitment by PECO to provide back-up power under the PECO Services Agreement, as well as PECO's marketing capabilities, will favorably affect the Company's competitive position.

NEPOOL

The Company is a party to the New England Power Pool ("NEPOOL") Agreement (the "NEPOOL Agreement") and is a member of NEPOOL. NEPOOL is open to all investor-owned, municipal and cooperative electric utilities in New England that are connected to the New England power grid. Effective November 13, 1995, the NEPOOL Agreement was amended to permit broader membership and participation in NEPOOL by power marketers and other non-utilities that transact business in the bulk power market in New England. The NEPOOL Agreement provides for coordinated planning of future facilities as well as the operation of nearly 100% of existing generating capacity in New England and of related transmission facilities as if they were one system. The NEPOOL Agreement imposes on its participants obligations concerning generating capacity reserves and the right to use major transmission lines. On occasions when one or more transmission lines are out of service, the quantity of power being produced by then operating generation plants may exceed the quantity of power that can be carried safely by the transmission system. In such instances, one or more generation plants may be taken off-line by NEPOOL. To date, the Seabrook Project has not been taken off-line in these instances. The Company believes that it is unlikely that the Seabrook Project would be taken off-line in such instances because NEPOOL prefers to take off-line non-nuclear plants which are less complex and less difficult to schedule than nuclear units.

The NEPOOL agreement also provides for central dispatch of the generating capacity of NEPOOL members with the objective of achieving economical use of the region's facilities. Pursuant to the NEPOOL Agreement, interchange sales (purchases from or sales to the pool by a NEPOOL member) are made at prices approximately equal to the fuel cost for generation without contribution to the support of fixed charges, if NEPOOL has the right to schedule delivery of the power. On rare occasions, unscheduled power is delivered, or "dumped," to the pool, for which no payment is made by NEPOOL. The Company does not expect to "dump" power to NEPOOL. NEPOOL members also jointly schedule generation plant maintenance to avoid capacity shortages in the NEPOOL area. The number of generation plants undergoing maintenance at any time affects the cost of replacement power in the market. Thus, the Company's operating revenues and costs are affected to some extent by the operations of plants of other members.

Nuclear Power, Energy and Utility Regulation

The Seabrook Project and the Company, as part owner of a licensed nuclear facility, are subject to the broad jurisdiction of the NRC, which is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health and safety, environmental and antitrust matters. The

Company has been, and will be, affected to the extent of its proportionate share by the cost of any such requirements made applicable to Seabrook Unit 1.

The Company is also subject to the jurisdiction of the FERC under Parts II and III of the Federal Power Act and, as a result, is required to file with FERC all contracts for the sale of electricity. FERC has the authority to suspend the rates at which the Company proposes to sell power, to allow such rates to go into effect subject to refund and to modify a proposed or existing rate if FERC determines that such rate is not "just and reasonable." FERC's jurisdiction also includes, among other things, the sale, lease, merger, consolidation or other disposition of facilities, interconnection of certain facilities, accounts, service and property records.

Because it is an EWG, the Company is not subject to the jurisdiction of the Securities and Exchange Commission (the "Commission") under the Public Utility Holding Company Act of 1935. In order to maintain its EWG status, the Company must continue to engage exclusively in the business of owning and/or operating all or part of one or more "eligible facilities" and to sell electricity only at wholesale (i.e., not to end users). An "eligible facility" is a facility used for the generation of electric energy exclusively at wholesale or used for the generation of electric energy and leased to one or more public utility companies. The term "facility" may include a portion of a facility. In the case of the Company, its 12.1% joint ownership interest in the Seabrook Project comprises an "eligible facility."

The Company is subject to regulation by the NHPUC in many respects including the issuance of securities, the issuance of debt, contracts with affiliates, forms of accounts, transfers of utility properties, mortgaging of utility property and other matters. The NHPUC does not regulate rates charged for sales of electricity at wholesale.

The NHPUC and the utilities regulatory authorities and state legislatures of several other states in which the Company sells electricity are considering a range of proposals relating to the deregulation of the utilities industry. It is not possible to predict what steps will be taken by these authorities and legislatures or their impact on the Company.

Nuclear Power Issues

Nuclear units in the United States have been subject to widespread criticism and opposition, which has led to construction delays, cost overruns, licensing delays and other difficulties. Various groups have sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste by litigation, legislation and participation in administrative proceedings. The Seabrook Project was the subject of significant public controversy during its construction and licensing and remains controversial. An increase in public concerns regarding the Seabrook Project or nuclear power in general could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

In the event of a permanent shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. While the owners of the Seabrook Project are accumulating a trust fund to pay decommissioning costs, if these costs exceed the amount of the trust fund, the owners (including the Company) will be liable for the excess.

Nuclear Related Insurance

In accordance with the Price Anderson Act, the limit of liability for a nuclear-related accident is approximately $8.9 billion, effective November 18, 1994. The primary layer of insurance for this liability is $200 million of coverage provided by the commercial insurance market. The secondary coverage is approximately $8.7 billion, based on the 110 currently licensed reactors in the United States. The secondary layer is based on a retrospective premium assessment of $79.3 million per nuclear accident per licensed reactor, payable at a rate not exceeding $10 million per year per accident and a maximum of $20 million per year. In addition, the retrospective premium is subject to inflation based indexing at five year intervals and, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection available, then each licensee can be assessed an additional 5% ($3.775 million) of the maximum retrospective assessment. With respect to the Seabrook Project, the Company would be obligated to pay its ownership share of any assessment resulting from a nuclear incident at any United States nuclear generating facility. The Company estimates its maximum liability per incident currently would be an aggregate amount of approximately $9.59 million per accident, with a maximum annual assessment of about $1.21 million per incident, per year.

In addition to the insurance required by the Price Anderson Act, the NRC regulations require licensees, including the Seabrook Project, to carry all risk nuclear property damage insurance in the amount of at least $1.06 billion, which amount must be dedicated, in the event of an accident at the reactor, to the stabilization and decontamination of the reactor to prevent significant risk to the public health and safety.

During 1995, the Company purchased business interruption insurance from Nuclear Electric Insurance Limited ("NEIL"). This policy is in effect from December 22, 1995 until September 15, 1996 and provides for the payment of a fixed weekly loss amount of $520,000 in the event of an outage at the Seabrook Project of more than 21 weeks resulting from property damage occurring from a "sudden fortuitous event, which happens by chance, is unexpected and unforeseeable." The maximum amount payable to the Company is $70.3 million. Under the terms of the policy, the Company is subject to a potential retrospective premium adjustment of up to approximately $650,000 should NEIL's board of directors deem that additional funds are necessary to preserve the financial integrity of NEIL. Since NEIL was founded in 1980, there has been no retrospective premium adjustment; however, there can be no assurance that NEIL will not make retrospective adjustments in the future. The liability for this retrospective premium adjustment ceases six years after the end of the policy unless prior demand has been made.

Nuclear Fuel

The Seabrook Project's joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. Many of these arrangements are pursuant to multi year contracts with concentrate or services providers. Based on the Seabrook Project's existing contractual arrangements, the Company believes that the Seabrook Project has available or under supply contract sufficient nuclear fuel for operations through approximately 2001. The next refueling, based on NAESCO's expectation for fuel consumption, is currently scheduled for June 1997. Uranium concentrate and conversion, enrichment and fabrication services currently are available from a variety of sources. The cost of such concentrate and such services varies based upon market factors.

Nuclear Waste Disposal

Costs associated with nuclear plant operations include amounts for disposal of nuclear wastes, including spent fuel, as well as for the ultimate decommissioning of the plants. Under the Nuclear Waste Policy Act of 1982 (the "NWPA"), the United States Department of Energy (the "DOE") is required (subject to various contingencies) to design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such waste and fuel. The NWPA specifies that the DOE provide for the disposal of such waste and spent nuclear fuel starting in 1998.

The owners of the Seabrook Project have entered into contracts with the DOE for disposal of spent nuclear fuel in accordance with the NWPA. In return for payment of the prescribed fees, the federal government is to take title to and dispose of the Seabrook Project's high level wastes and spent nuclear fuel beginning no later than 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010, notwithstanding the DOE's statutory and contractual responsibility to begin disposal of high-level radioactive waste and spent fuel, beginning not later than January 31, 1998.

Until the federal government begins receiving such materials in accordance with the NWPA, operating nuclear generating units such as the Seabrook Project will need to retain high level wastes and spent fuel on-site or make other provisions for their storage. The Company has been advised by the Managing Agent that on-site storage facilities for the Seabrook Project are expected to be adequate until at least 2010.

Disposal costs for low-level radioactive wastes ("LLW") that result from normal operation of nuclear generating units have increased significantly in recent years and are expected to continue to rise. The cost increases are functions of increased packaging and transportation costs and higher fees and surcharges charged by the disposal facilities. Pursuant to the Low-Level Radioactive Waste Policy Act of 1980, each state was responsible for providing disposal facilities for LLW generated within the state and was authorized to join with other states into regional compacts to jointly fulfill their responsibilities. However, pursuant to the Low-Level Radioactive Waste Policy Amendments Act of 1985, each state in which a currently operating disposal facility is located (South Carolina, Nevada and Washington) is allowed to impose volume limits and a surcharge on shipments of LLW from states that are not members of the compact in the region in which the facility is located. On June 19, 1992, the United States Supreme Court issued a decision upholding certain parts of the Low-Level Radioactive Waste Policy Amendments Act of 1985, but invalidating a key provision of that law requiring each state to take title to LLW generated within that state if the state fails to meet federally-mandated deadlines for siting LLW disposal facilities. The decision has resulted in uncertainty about states' continuing roles in siting LLW disposal facilities and may result in increased LLW disposal costs and the need for longer interim LLW storage before a permanent solution is developed.

In April 1995, a privately owned facility in Utah was approved as a disposal facility for certain types of LLW. Additionally, the Barnwell, South Carolina disposal facility was reopened in July 1995 to all states except North Carolina as a result of legislation passed by the South Carolina legislature. The Seabrook Project began shipping certain LLW to the Utah facility in December 1995. All LLW generated by the Seabrook Project which exceeds the maximum radioactivity level of LLW accepted by the Utah facility and LLW resulting from the Seabrook Project's operation prior to that date is stored on-site.

Decommissioning

NRC licensing requirements and restrictions are also applicable to the decommissioning of nuclear generating units at the end of their service lives, and the NRC has adopted comprehensive regulations concerning decommissioning planning, timing, funding and environmental review. Any changes in NRC requirements or technology can increase estimated decommissioning costs.

Along with the other Participants, the Company is responsible for its pro rata share of the decommissioning and cancellation costs for Seabrook. The decommissioning funding schedule is determined by the New Hampshire Nuclear Decommissioning Financing Committee (the "NDFC"). The NDFC reviews the decommissioning funding schedule for the Seabrook Project at least annually and, for good cause, may increase or decrease the amount of the funds or alter the funding schedule. The Company pays its share of decommissioning costs on a monthly basis.

The estimated cost to decommission the Seabrook Project, based on a study performed in 1994 for the lead owner of the Plant, is approximately $414 million in 1995 dollars and $2.1 billion in 2026 dollars, assuming a 36-year life for the facility and a future escalation rate of 4.25%. Based on this estimate, the current value of the Company's share of this liability in 1995 dollars is approximately $50.2 million.

The Seabrook Project's decommissioning estimate and funding schedule is subject to review each year by the New Hampshire Nuclear Decommissioning Finance Committee ("NDFC"). The review of the 1996 estimate and funding schedule by the NDFC is currently scheduled for May 1996. Although the owners of the Seabrook Project are accumulating funds in an external trust to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners, including the Company, would remain liable for the excess.

On November 15, 1992 , the Company, the Bondholder's Committee and the Predecessor's former parent, Eastern Utilities Associates ("EUA") entered into a settlement agreement which resolved certain proceedings against EUA brought by the Bondholder's Committee. Under the settlement agreement EUA reaffirmed its guarantee in an amount not to exceed $10 million of the Company's future decommissioning costs of Seabrook Unit 1 in the event that the Company is unable to pay its share of such decommissioning costs.

Environmental Regulation

The Seabrook Project, like other electric generating stations, is subject to standards administered by federal, state and local authorities with respect to the siting of facilities and associated environmental factors. The United States Environmental Protection Agency (the "EPA"), and certain state and local authorities, have jurisdiction over releases of pollutants, contaminants and hazardous substances into the environment and have broad authority in connection therewith, including the ability to require installation of pollution control devices and remedial actions. The NRC has promulgated a variety of standards to protect the public from radiological pollution caused by the normal operation of nuclear generating facilities.

The EPA issued a National Pollutant Discharge Elimination System permit, valid for a period of five years, to NAESCO on October 30, 1993 authorizing discharges from Seabrook Station into the Atlantic Ocean and the Browns River in accordance with limitations, monitoring requirements and conditions specified in the permit. On August 31, 1994, the New Hampshire Department of Environmental Services issued to NAESCO permits to operate two auxiliary boilers and two emergency diesel generators in accordance with New Hampshire RSA 125-C. These permits, which are effective until August 31, 1997, prescribe limits for the emission of air pollutants into the ambient air as well as record keeping and other reporting criteria.

In some environmental areas, the NRC and the EPA have overlapping jurisdiction. Thus, NRC regulations are subject to all conditions imposed by the EPA and a variety of federal environmental statutes, including obtaining permits for the discharge of pollutants (including heat, which is discharged by the Seabrook Project) into the nation's navigable waters. In addition, the EPA has established standards, and is in the process of reviewing existing standards, for certain toxic air pollutants, including radionuclides, under the Clean Air Act which apply to NRC-licensed facilities. The effective date for the new EPA radionuclide standards has been stayed as applied to nuclear generating units. Environmental regulation of the Seabrook Project may result in material increases in capital and operating costs, delays or cancellation of construction of planned improvements, or modification or termination of operation of existing facilities.

Energy Policy Act

The Energy Act addresses many aspects of national energy policy and includes important changes for electric utilities and registered holding companies. For example, the Energy Act grants FERC new authority to mandate transmission access for QFs, EWGs and traditional utilities. It is not possible to predict the impact which the Energy Act and the rules and regulations which will be promulgated by various regulatory agencies pursuant to the Energy Act will have on the Company. It is also not possible to predict the timing or content of future energy policy legislation and the significance of such legislation to the Company. Various issues not addressed by the Energy Act, including regional planning and transmission arrangements, could be addressed in future legislation.

Employees and Management

The Company has only two employees, its President, John A. Tillinghast, and its Vice President and General Counsel, Frank W. Getman Jr. See "Executive Officers" below. A Management and Administrative Services Agreement was in effect during 1995 between the Company and URI which provided for URI to provide a full range of services to the Company including management, accounting and bookkeeping, budgeting and regulatory compliance. Under the Management and Administrative Services Agreement with URI, the Company paid URI $225,000 per year for senior executive management services and reimbursed day-to-day operational services at URI's cost plus 25%. The Company terminated this agreement effective January 2, 1996. The Company has assumed responsibility for many of the services previously provided by URI. Certain administrative functions, including accounting and bookkeeping, continue to be provided to the Company by other parties, but the Company expects to assume control of these functions by the end of the second quarter of 1996.

Item 2. *Properties.*

The Company's principal asset is its 12.1% joint ownership interest in the Seabrook Project. The Seabrook Project is a nuclear-fueled, steam electricity, generating plant located in Seabrook, New Hampshire, which was planned to have two Westinghouse pressurized water reactors, Seabrook Unit 1 and Seabrook Unit 2 (each with a rated capacity of 1,150 megawatts), utilizing ocean water for condenser cooling purposes. Seabrook Unit 1 entered commercial services on August 19, 1990. Seabrook Unit 2 has been canceled. See "Item 1. Business — The Seabrook Project."

Item 3. *Legal Proceedings.*

The Company filed applications for abatement of its 1994 property taxes with the Towns of Seabrook, Hampton and Hampton Falls, New Hampshire (the "New Hampshire Towns"). Each of the New Hampshire Towns denied the Company's abatement requests. On December 22, 1994 with respect to Hampton and Hampton Falls and February 18, 1995 with respect to Seabrook, the Company filed appeals with the Board of Land and Tax Appeals (the "1994 Tax Appeals"). The Company believes that the New Hampshire Towns significantly overvalued the Company's interest in the Seabrook Project. The 1994 Tax Appeals are presently pending and the Company is unable to predict the outcome.

In December 1995, the Town of Seabrook, New Hampshire (the "Town of Seabrook") issued a bill for property taxes for the second half of 1995 to North Atlantic Energy Corp., et al. The Town of Seabrook informed the Company that it believed the Company's share of this bill was equal to $1,293,000. The Company did not pay the bill because the Company believes that the Town of Seabrook's assessment of the Company's interest in the Seabrook Project is overstated and because the bill fails to recognize the Company as an independent taxpayer with a separately assessed and valued parcel of real estate. While the Company refused to pay the December property tax bill, the Company has accrued the full $1,293,000 liability related to the bill. A Notice of Lien will be issued by the Town of Seabrook if the Company does not pay the bill by March 22, 1996.

Item 4. *Submission of Matters to a Vote of Security Holders*

Not Applicable.

Executive Officers of the Registrant

The following table sets forth the names and ages of, and the positions and offices with the Company as of February 29, 1996 held by, all executive officers of the Company:

Name	Age	Position
John A. Tillinghast	68	Chief Executive Officer, President, Treasurer and Chairman of the Board of Directors
Frank W. Getman, Jr.	32	Vice President, Secretary and General Counsel

Mr. Tillinghast has served as Chief Executive Officer, President, Treasurer and a director of the Company since November 23, 1994. Since 1987, Mr. Tillinghast has served as President and the sole stockholder of Tillinghast Technology Interests, Inc. ("TILTEC"), a private consulting firm that provides services to various corporations relative to cogeneration, alternative energy projects, third party power generation and general restructuring of the U.S. utility industry. In addition, from 1986 to 1993, Mr. Tillinghast served as Chairman of the Energy Engineering Board of the National Academy of Sciences. He holds an M.S. in Mechanical Engineering from Columbia University.

Mr. Getman has served as Vice President, Secretary and General Counsel since August 1, 1995. From September 1991 to August 1995, Mr. Getman was an attorney with the law firm of Hale and Dorr, Boston, Massachusetts. Mr. Getman holds J.D. and M.B.A. degrees from Boston College and a B.A. in Political Science from Tufts University.

PART II

Item 5. ***Market for Registrant's Common Equity and Related Stockholder Matters.***

From January 27, 1995 to April 17, 1995, the Company's Common Stock traded on the Nasdaq over-the-counter market and was quoted on the Nasdaq OTC Bulletin Board. Transfers occurred infrequently and at a low volume level. During this period, the low and high prices at which transactions in the Company's Common Stock occurred on the Nasdaq OTC Bulletin Board were $7.12 and $9.00 per share, respectively. These prices may have reflected inter-dealer prices, without retail mark-ups, mark downs or commissions, and may not have necessarily represented actual transactions.

The Company's Common Stock commenced trading on the Nasdaq National Market ("NNM") on April 18, 1995 under the symbol "GBPW". Following are the reported high and low sales prices of the Company's Common Stock on the NNM as reported daily in the Wall Street Journal for each quarter in 1995 since the Company's Common Stock commenced trading on the NNM:

	1995	
	High	Low
Second quarter (beginning April 18, 1995)	9¾	7
Third quarter	9	7¾
Fourth quarter	9¼	6¾

As of December 31, 1995, the Company had 73 holders of record of its Common Stock.

The Company has never paid cash dividends on the Common Stock. The Company currently expects that it will retain all of its future earnings and does not anticipate paying a dividend in the foreseeable future.

Item 6. ***Selected Financial Data.***

Selected Financial Data

The following table sets forth selected financial data and other operating information of the Company. The selected financial data presented below for periods subsequent to November 23, 1994 give effect to the consummation of the Company's Reorganization Plan and to the adoption of fresh start reporting by the Company as of that date in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7 Financial Reporting by Entities in Reorganization under the Bankruptcy Code". Accordingly, periods prior to November 23, 1994 have been designated "Predecessor Company" or the "Predecessor" and periods subsequent to November 23, 1994 have been designated "Reorganized Company" or the "Company". Selected balance sheet and statement of income (loss) data of the Predecessor Company periods are not comparable to those of the Reorganized Company periods and a line has been drawn in the tables to separate the Predecessor financial data from the Company financial data.

The following data presents (i) selected financial data of the Reorganized Company as of December 31, 1995 and the period from November 24, 1994 to December 31, 1994 and (ii) selected financial data of the Predecessor Company for the period from January 1, 1994 to November 23, 1994 and for each of the three years in the period ended December 31, 1993. The information below should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Company's financial statements, including the notes thereto, contained elsewhere in this Report.

SELECTED FINANCIAL DATA
(Dollars in Thousands)

	Reorganized Company		Predecessor Company			
	December 31,	November 24 to December 31	January 1 to November 23	For the Years Ended December 31,		
	1995	1994	1994	1993	1992	1991
Income Statement Data:						
Operating Revenues	$ 24.524	$ 3.129	$ 13.989	$ 24,620	$ 23,027	$ 20,919
Fuel, Operation and Maintenance	24,899	2,409	21.762	22,991	26,823	27,896
Net (Loss) Income	(6.059)	182	131.385	(9,433)	(47,468) (2)	(19,792)

	Reorganized Company December 31,		Predecessor Company December 31,		
	1995	1994	1993	1992	1991
Balance Sheet Data:					
Cash & Cash Equivalents	16,469	22,217	138	4,817	133
Working Capital (1)	20,516	27,169	(289.585)	(284,819)	(160,756)
Total Assets	138,771	145,666	324,590	333,758	359,058
Decommissioning Liability	50,228	48,530	—	—	—
Capitalization:					
Long-Term Debt (excluding current maturities) (1)	0	0	0	0	180,000
Common Equity	82.223	88,292	(139.783)	(130,350)	(82,882)
Cumulative Convertible Preferred Stock			63.090	63,090	63,090
Total Capitalization	82.233	88.292	(76.693)	(67,260)	160,208

(1) As a result of Predecessor's bankruptcy filing, the Predecessor was in default under the indenture pursuant to which the secured notes were issued. Long-Term Debt of the Predecessor was thereafter classified as a current liability subject to compromise.

(2) In 1992 the Predecessor Company reversed all accumulated tax benefits related to carry forwards of net operating losses and alternative minimum tax credits to reflect the anticipated imposition of certain tax law limitations and the impact of certain settlement agreements between the Predecessor Company and EUA.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

Emergence from Chapter 11

On February 28, 1991, the Company filed a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. On November 23, 1994 (the "Effective Date"), a formal confirmation order by the U.S. Bankruptcy Court for the District of New Hampshire with respect to the Company's Reorganization Plan became effective. At that time, the Company emerged from bankruptcy. As a result of the Chapter 11 proceeding and in accordance with the provisions of the Reorganization Plan, the capital structure of the Company was completely changed. In particular, as part of its Chapter 11 proceeding, the Company discharged all of its pre-petition debt, which consisted primarily of the approximately $280 million principal amount of outstanding Notes and unpaid accrued interest on the Notes of approximately $14 million, and raised gross proceeds of $35 million in the Reorganization Plan. See "Business — Bankruptcy Proceeding and Reorganization." Thus, as a result, the Company's net worth increased significantly and the Company was relieved of the obligation to make principal and interest payments on the Notes.

The following discussion focuses solely on operating revenues and operating expenses which are presented in a substantially consistent manner for all of the periods presented. As a result of the Chapter 11 proceeding and subsequent effectiveness of the Reorganization Plan on November 23, 1994, the 1994 Statement of

Income represents separately the results of operations of the predecessor company prior to November 23, 1994 from the results of operations of the Company after that date.

On the Effective Date, the Company adopted a "Fresh Start" Balance Sheet. That Balance Sheet reflects the assets and liabilities of the Company at their estimated fair values as of the Effective Date, including the net proceeds of the Reorganization Plan Equity Financing, and eliminating liabilities discharged under the Reorganization Plan.

Overview

The Company reported an operating loss in each of the year ended December 31, 1995, the combined twelve-month period ended December 31, 1994 and the year ended December 31, 1993. These losses were primarily due to sales of the Company's share of electricity from the Seabrook Project in the short-term market at prices resulting in revenues substantially below actual expenses.

The Seabrook Project from time to time experiences both scheduled and unscheduled outages. The Company incurs losses during outage periods due to the loss of all operating revenues and additional costs associated with the outages as well as continuing operating and maintenance expenses and depreciation. Unscheduled outages or operation of the unit at reduced capacity can occur due to the automatic operation of safety systems following the detection of a malfunction. In addition, it is possible for the unit to be shut down or operated at reduced capacity based on the results of scheduled and unscheduled inspections and routine surveillance by Seabrook Project personnel. It is not possible for the Company to predict the frequency or duration of any future unscheduled outages; however, it is likely that such unscheduled outages will occur. The Seabrook Project Managing Agent has scheduled the next refueling outage for June 1997. Refueling outages are scheduled generally every 18-24 months depending upon the Seabrook Project capacity factor and the rate at which the nuclear fuel is consumed.

This Annual Report on Form 10-K contains forward-looking statements. For this purpose, any statements contained herein which are not statements of historical fact may be deemed to be forward-looking statements. Without limiting the foregoing, the words "believes," "anticipates," "plans," "expects" and similar expressions are intended to identify forward-looking statements. There are a number important factors that could cause the Company's actual results to differ materially from those indicated by the forward-looking statements. These factors include, without limitation, those set forth below under the caption "Certain Factors That May Affect Future Results."

Results of Operations

Operating Revenues

Years Ended December 31, 1995, 1994 and 1993

Operating revenues for 1995 increased by approximately $7.4 million, or 43%, as compared with the combined twelve months ended 1994. The increase was due to reduced scheduled and unscheduled outage time during 1995, with an average capacity factor of 83.2% in 1995 as compared with 61.6% in the combined twelve months ended 1994. Operating revenues were also favorably affected in 1995 by an increase in the sales price per kWh to 2.41 cents per kWh as compared with 2.27 cents per kWh in the combined twelve months ended 1994. The Company's cost of power (determined by dividing Total Operating Expenses by the Company's 12.1% share of the power produced by the Seabrook Project during the applicable period) decreased by 34.7% to 3.18 cents per kWh in 1995 as compared with 4.88 cents per kWh in the combined twelve months ended 1994, primarily as a result of reduced depreciation and amortization expenses in 1995 resulting from the write down to fair value of all of the Company's assets following its emergence from bankruptcy in November 1994.

Operating revenues for the combined twelve months ended 1994 decreased by approximately $7.5 million, or 30.5%, in comparison with 1993. The decrease was primarily due to greater scheduled and unscheduled outages at the Seabrook Project during 1994 than in 1993, with an average capacity factor of 61.6% in 1994 in comparison with 89.9% in 1993. The sales price per kilowatt-hour power was substantially unchanged, increasing to 2.27 cents in the combined twelve-month period in 1994 from 2.24 cents in 1993. The Company's cost of power for the same periods increased by 68.3% to 4.88 cents per kWh in the combined twelve-month period in 1994 as compared with 2.90 cents per kWh in 1993, primarily as a result of the outages in the combined twelve months ended 1994.

Expenses

Years Ended December 31, 1995, 1994 and 1993

Total Operating Expenses (excluding depreciation and all taxes) for 1995 increased $0.7 million, or 3.0%, in comparison with the combined twelve months ended 1994, primarily as a result of increased administrative and general expenses. This increase was partially offset by lower maintenance costs during the Seabrook Project's 1995 scheduled outage. Depreciation and amortization expenses decreased by 59.6% to $3.3 million during 1995 as compared with $8.3 million in the combined twelve months ended 1994. The decrease was the result of a reduction in the depreciable value of the Company's investment in the Seabrook Project due to the write down to fair value of all the Company's assets following its emergence from bankruptcy in November 1994. In the combined twelve months ended 1994, as part of the its emergence from bankruptcy, the Company wrote off $137.9 million of assets and liabilities. Interest income increased in 1995 to $1.5 million as a result of the Company's significantly higher cash and investment balances in 1995.

Total Operating Expenses (excluding depreciation and all taxes) for the combined twelve-month period in 1994 increased $1.2 million, or 5.1%, in comparison with 1993, primarily as a result of increased maintenance costs during the Seabrook Project's 1994 outages. Taxes Other Than Income increased for the combined twelve-month period in 1994 by approximately $0.4 million, or 10.4%, over 1993, reflecting changes in the manner in which the Company accrued for this liability as a result of the uncertainty regarding the timing and magnitude of the NOLs described below.

Net Operating Losses

For federal income tax purposes, as of December 31, 1995, the Company had net operating loss carry forwards ("NOLs") of approximately $167 million, which are scheduled to expire between 2005 and 2010. Because the Company has experienced one or more ownership changes, within the meaning of Section 382 of the Internal Revenue Code of 1986, as amended, an annual limitation is imposed on the ability of the Company to use $136 million of these carryforwards. The Company's best estimate at this time is that the annual limitation on the use of $136 million of the Company's NOLs is approximately $5.5 million per year. The Company's other $31 million of NOLs are not currently subject to such limitations.

Liquidity and Capital Resources

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses, including, without limitation, operation and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of the level of Seabrook Unit 1's operations. The Company currently is selling most of its power in the Northeast United States short-term wholesale power market. The cash generated from electricity sales by the Company is and has been less than the Company's ongoing cash requirements. The Company expects that it will continue to incur cash deficits until the prices at which it is able to sell its share of the Seabrook Project electricity increase, which may be a number of years, if ever. The Company intends to cover such deficits with its cash and short-term investments which totaled approximately $16.5 million at December 31, 1995. However, if the Seabrook Project operates at a capacity factor below historical levels, or if expenses associated with the ownership or operation of the Seabrook Project, including without limitation decommissioning costs, are materially higher than anticipated, or if the prices at which the Company is able to sell its share of the Seabrook Project electricity do not increase at the rates and within the time expected by the Company, the Company would be required to raise additional capital, either through a debt financing or an equity financing, to meet its ongoing cash requirements.

The Company's principal asset available to serve as collateral for borrowings is its 12.1% joint interest in the Seabrook Project. Pursuant to a power purchase agreement, dated as of April 1, 1993, between the

Company and UNITIL Power Corp., the Company's interest in the Seabrook Project is encumbered by a mortgage. This mortgage may be subordinated to up to $80 million of senior secured financing. See "Business — Power Purchase Agreement."

The Company's cash and short-term investments decreased approximately $5.7 million during 1995, primarily as a result of the operating loss discussed above plus $7.5 million of capital expenditures for plant and nuclear fuel, payments of $1.0 million to the decommissioning trust fund and payments of $2.7 million for bankruptcy-related reorganization expenses. Partially offsetting the items listed above were non-cash charges to income of $7.9 million for depreciation and amortization.

The Company's fiscal 1995 decommissioning expenses totaled approximately $1.0 million. The decommissioning funding schedule is determined by the New Hampshire Nuclear Decommissioning Financing Committee (the "NDFC"), which reviews such schedule for the Seabrook Project at least annually. The Company's decommissioning expenses for fiscal 1996 and fiscal 1997 will depend upon the outcome of pending proceedings before the NDFC. The Company expects to use revenues from the sale of power to pay these decommissioning expenses.

The Company anticipates that its share of the Seabrook Project's capital expenditures for the 1996 fiscal year will total approximately $2.7 million, primarily for nuclear fuel.

Certain Factors That May Affect Future Results

The following important factors, among others, could cause actual results to differ materially from those indicated by forward-looking statements made in this Annual Report on Form 10-K.

Ownership of Single Asset. The Company owns a single principal asset, its 12.1% joint interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire. Accordingly, the Company's results of operations are completely dependent upon the successful and continued operation of the Seabrook Project. In particular, if the Seabrook Project experiences unscheduled outages of significant duration, the Company's results of operations will be materially adversely affected.

History of Losses; Implementation of Business Strategy. The Company has never reported an operating profit since its incorporation. The Company's business strategy is to seek purchasers for its share of the Seabrook Project electricity output at prices, either in the short-term market or pursuant to medium or long-term contracts, significantly in excess of the prices currently available in the short-term wholesale electricity market since sales at current short-term rates do not result in sufficient revenue to enable the Company to meet its cash requirements for operations, maintenance and capital related costs. The Company's ability to obtain such higher prices will depend on regional, national and worldwide energy supply and demand factors which are beyond the control of the Company. There can be no assurance that the Company ever will be able to sell power at prices that will enable it to meet its cash requirements.

Liquidity Needs. The Company had approximately $16.5 million in cash, cash equivalents and short-term investments at December 31, 1995. The Company believes that such cash, together with the anticipated proceeds from the sale of electricity by the Company, will be sufficient to enable the Company to meet its cash requirements until the prices at which the Company can sell its electricity increase sufficiently to enable the Company to cover its annual cash requirements. However, if the Seabrook Project operates at a capacity factor below historical levels, or if expenses associated with the ownership or operation of the Seabrook Project, including without limitation decommissioning costs, are materially higher than anticipated, or if the prices at which the Company is able to sell its share of the Seabrook Project electricity do not increase at the rates and within the time expected by the Company, the Company would be required to raise additional capital, either through a debt financing or an equity financing, to meet its ongoing cash requirements. There is no assurance that the Company would be able to raise such capital or that the terms on which any additional capital is available would be acceptable. If additional funds are raised by issuing equity securities, dilution to then existing stockholders will result.

Changes in Power Sale Contract Terms Available in Wholesale Power Market. In the past, wholesale sellers of electric power, which typically were regulated electric utilities, frequently entered into medium or long-term power sale contracts providing for prices in excess of the prices available in the short-term market. Recently, increased competition in the wholesale electric power market, reduced growth in the demand for electricity and low prices in the short-term market have reduced the willingness of wholesale power purchasers to enter into medium or long-term contracts and have reduced the prices obtainable from such contracts.

Risks in Connection with Joint Ownership of Seabrook Project. The Company is required under the Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units dated May 1, 1973, as amended, by and among the Company and the other 11 utility companies who are owners of the Seabrook Project (the "JOA"), to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses, including without limitation operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of the level of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA entitles certain other joint owners of the Seabrook Project to purchase the Company's interest in the Seabrook Project for 75% of the then fair market value thereof.

In addition, the failure to make monthly payments under the JOA by owners of the Seabrook Project other than the Company may have a material adverse effect on the Company by requiring the Company to pay a greater proportion of the Seabrook Unit 1 and Seabrook Unit 2 expenses in order to preserve the value of its share of the Seabrook Project. In the past, certain of the owners of the Seabrook Project other than the Company have not made their full respective payments.

The Seabrook Project is owned by the Company and the other owners thereof as tenants in common, with the various owners holding varying ownership shares. This means that the Company, which owns only a 12.1% interest, does not have control of the management of the Seabrook Project. As a result, decisions may be made affecting the Seabrook Project, notwithstanding the Company's opposition.

Certain costs and expenses of operating the Seabrook Project or owning an interest therein, such as certain insurance and decommissioning costs, are subject to increase or retroactive adjustment based on factors beyond the Company's control. The cost of disposing of Unit 2 of the Seabrook Project is not known at this time. These various costs and expenses may adversely effect the Company, possibly materially.

Extensive Government Regulation. The Seabrook Project is subject to extensive regulation by federal and state agencies, including the NRC, FERC and the NHPUC. Compliance with the various requirements of the NRC and FERC is expensive. Noncompliance with NRC requirements may result, among other things, in a shutdown of the Seabrook Project.

The NRC has promulgated a broad range of regulations affecting all aspects of the design, construction and operation of a nuclear facility, such as the Seabrook Project, including performance of nuclear safety systems, fire protection, emergency response planning and notification systems, insurance and quality assurance. The NRC retains authority to modify, suspend or withdraw operating licenses, such as that pursuant to which the Seabrook Project operates, at any time that conditions warrant. The NRC might order Seabrook Unit 1 shut down (i) if flaws were discovered in the construction or operation of Seabrook Unit 1, (ii) if problems developed with respect to other nuclear generating plants of a design and construction similar to Unit 1, or (iii) if accidents at other nuclear facilities suggested that nuclear generating plants generally were less safe than previously believed.

Risk of Nuclear Accident. Nuclear reactors have been used to generate electric power for more than 30 years and there are currently more than 100 nuclear reactors used for electric power generation in the United States. Although the safety record of such nuclear reactors in the United States generally has been very good, accidents and other unforeseen problems have occurred both in the United States and elsewhere, including the well-publicized incidents at Three Mile Island in Pennsylvania and Chernobyl in the former Soviet Union. The consequences of such an accident can be severe, including loss of life and property damage, and the available insurance coverage may not be sufficient to pay all the damages incurred.

Public Controversy Concerning Nuclear Power Plants. Substantial controversy has existed for some time concerning nuclear generating plants and over the years such opposition has led to construction delays, cost overruns, licensing delays, demonstrations and other difficulties. The Seabrook Project was the subject of significant public controversy during its construction and licensing and remains controversial. An increase in public concerns regarding the Seabrook Project or nuclear power in general could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

Waste Disposal; Decommissioning Cost. There has been considerable public concern and regulatory attention focused upon the disposal of low- and high-level nuclear wastes produced at nuclear facilities and the ultimate decommissioning of such facilities. As to waste disposal concerns, both the federal government and the State of New Hampshire are currently delinquent in the performance of their statutory obligations. This has necessitated on-site storage of such wastes at the Seabrook Project. Although LLW storage facilities in Utah and South Carolina became available in 1995, certain LLW continue to be stored on-site at the Seabrook Project. The Seabrook Project anticipates increasing its on-site storage capacity for low-level wastes in 1996. The increased capacity is expected to be sufficient through 2006. In addition, the Managing Agent has advised the Company that the Seabrook Project has adequate on-site storage capacity for high-level wastes until approximately 2010.

As to decommissioning, the NRC regulations require that upon permanent shutdown of a nuclear facility, appropriate arrangements for full decontamination and decommissioning of the facility be made. These regulations include a requirement to set aside during operation sufficient funds to defray decommissioning costs. While the owners of the Seabrook Project are accumulating a trust fund to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners (including the Company) would remain liable for the excess. Moreover, the amount that is required to be deposited in the trust fund is subject to periodic review and adjustment by an independent commission of the State of New Hampshire, which could result in material increases in such amounts. Such a review is currently in process.

Intense Competition. The Company sells its share of Seabrook Project electricity primarily into the Northeast United States wholesale electricity market. There are a large number of suppliers to this market and a surplus of electricity, resulting in intense competition. A primary source of competition comes from traditional utilities, many of which presently have excess capacity. In addition, non-utility wholesale generators of electricity, such as independent power producers ("IPPs"), Qualifying Facilities ("QFs") and EWGs, as well as power marketers and brokers, actively sell electricity in this market. The Company may face increased competition, primarily based on price, from all such sources in the future.

Item 8. ***Financial Statements and Supplementary Data.***

The response to this item is submitted in the response found under Item 14(a)(i) in this report.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

Coopers & Lybrand L.L.P., whose report for the year ended December 31, 1993, appears elsewhere in this Annual Report on Form 10-K, were the Company's independent accountants until November 23, 1994. In connection with the Company's bankruptcy proceeding, the Bondholders' Committee determined to select a new accounting firm to be engaged by the Company following the Company's emergence from bankruptcy. Coopers & Lybrand L.L.P. did not resign and did not decline to stand for reelection. During the period of Coopers & Lybrand L.L.P.'s engagement by the Company, there were no disagreements between Coopers & Lybrand L.L.P. and the Company on any matters of accounting principles or practices, financial statement disclosure or auditing scope or procedure and no reportable events relating to the relationship between the Company and Coopers & Lybrand L.L.P.

On November 26, 1993 the Bankruptcy Court approved the Company's selection of Arthur Andersen LLP as the Company's independent accountant, to be effective only upon the Company's emergence from bankruptcy. Prior to November 23, 1994 the Predecessor Company had not consulted Arthur Andersen LLP regarding the application of accounting principles to specified transactions or the type of audit opinion that might be rendered on the Company's financial statements during the periods from January 1, 1991 through December 31, 1993.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

(a) *Directors.* The information with respect to directors required under this item is incorporated herein by reference to the section captioned "Election of Directors" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on April 16, 1996.

(b) *Executive Officers.* The information with respect to executive officers required under this item is incorporated herein by reference to Part I of this Report.

Item 11. ***Executive Compensation.***

The information required under this item is incorporated herein by reference to the sections entitled "Election of Directors — Compensation for Directors," "— Executive Compensation," "— Employment Agreements," "— Report of the Compensation Committee," "— Stock Performance Graph" and "Approval of the 1995 Stock Option Plan" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on April 16, 1996.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

The information required under this item is incorporated herein by reference to the section entitled "Security Ownership of Certain Beneficial Owners and Management" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on April 16, 1996.

Item 13. ***Certain Relationships and Related Transactions.***

The information required under this item is incorporated herein by reference to the sections entitled "Election of Directors — Employment Agreements" and "— Certain Transactions" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on April 16, 1996.

PART IV

Item 14. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K.***

(a) *Documents filed as a part of this Form 10-K:*

1. *Financial Statements.* The Consolidated Financial Statements listed in the Index to Consolidated Financial Statements and Financial Statement Schedules are filed as part of this Annual Report on Form 10-K.

2. *Financial Statement Schedules.* The Financial Statement Schedules listed in the Index to Consolidated Financial Statements and Financial Statement Schedules are filed as part of this Annual Report on Form 10-K.

3. *Exhibits.* The Exhibits listed in the Exhibit Index immediately preceding such Exhibits are filed as part of this Annual Report on Form 10-K.

(b) *Reports on Form 8-K:*

None.

INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
Great Bay Power Corporation and

To the Director of
Great Bay Power Corporation (formerly EUA Power Corporation)

We have audited the accompanying balance sheets of Great Bay Power Corporation (a New Hampshire corporation) as of December 31, 1995 and 1994 and the related statements of income, changes in stockholders' equity and cash flows for the year ended December 31, 1995 and the period from November 24, 1994 to December 31, 1994. We have also audited the accompanying statements of income, changes in stockholders' equity and cash flows of Great Bay Power Corporation (formerly EUA Power Corporation, the "Predecessor") for the period from January 1, 1994 to November 23, 1994. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to about present fairly, in all material respects, the financial position of Great Bay Power Corporation as of December 31, 1995 and 1994, and the results of the operations and cash flows of Great Bay Power Corporation and Great Bay Power Corporation (formerly EUA Power Corporation, the "Predecessor") for the year ended December 31, 1995, and the periods from November 24, 1994 to December 31, 1994 and January 1, 1994 to November 23, 1994, respectively, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

Boston, Massachusetts
January 26, 1996

GREAT BAY POWER CORPORATION
BALANCE SHEET
(Dollars in Thousands)

	December 31, 1995	December 31, 1994
Assets:		
Current Assets:		
Cash & Cash equivalents	$ 8,874	$ 18,533
Short-term Investments, at market	7,595	3,684
Accounts Receivable	1,535	2,598
Materials & Supplies	4,230	4,846
Prepayments & Other Assets	1,249	2,976
Total Current Assets	23,483	32,637
Property, Plant, & Equipment:		
Utility Plant	104,696	101,308
Less: Accumulated Depreciation	(4,165)	(95)
Net Utility Plant	100,531	101,213
Nuclear Fuel	9,925	10,556
Less: Accumulated Amortization	(304)	(2,118)
Net Nuclear Fuel	9,621	8,438
Net Property, Plant & Equipment	110,152	109,651
Other Assets:		
Decommissioning Trust Fund	5,108	3,290
Deferred Debits & Other	28	88
Total Other Assets	5,136	3,378
Total Assets	$138,771	$145,666
Liabilities and Stockholders' Equity:		
Current Liabilities:		
Accounts Payable and Accrued Expenses	$ 237	$ 303
Taxes Accrued	1,293	1,166
Reorganization Expenses	0	2,653
Miscellaneous Current Liabilities	1,437	1,346
Total Current Liabilities	2,967	5,468
Operating Reserves:		
Decommissioning Liability	50,228	48,530
Miscellaneous Other	671	719
Total Operating Reserves	50,899	49,249
Other Liabilities & Deferred Credits	2,672	2,563
Accumulated Deferred Taxes	0	94
Commitments & Contingencies		
Stockholders' Equity:		
Common stock, $.01 par value		
Authorized, issued and outstanding — 8,000,000 shares	80	80
Additional paid-in capital	88,030	88,030
Retained earnings	(5,877)	182
Total Stockholders' Equity	82,233	88,292
Total Liabilities and Stockholders' Equity	$138,771	$145,666

(The accompanying notes are an integral part of these statements.)

GREAT BAY POWER CORPORATION
STATEMENT OF INCOME
(Dollars in Thousands)

	Successor		Predecessor
	January 1 to December 31, 1995	November 24 to December 31, 1994	January 1 to November 23, 1994
Operating Revenues	$24,524	$3,129	$ 13,989
Operating Expenses:			
Production	17,433	1,836	16,891
Transmission	934	70	834
Administrative & General	6,532	503	4,037
Depreciation & Amortization	3,339	240	8,027
Taxes other than Income	4,143	346	3,934
Total Operating Expenses	32,381	2,995	33,723
Operating Income (Loss)	(7,857)	134	(19,734)
Other (Income) Deductions:			
Write-down of Assets & Liabilities	—	—	$137,908
Reorganization Expenses	—	—	4,038
Interest and Divident (Income) Expense	(1,546)	(143)	760
Miscellaneous	(198)	1	(102)
Total Other Deductions	(1,744)	(142)	142,604
Earnings (Loss) Before Income Taxes	(6,113)	276	(162,338)
Income Taxes:			
Current	(54)	—	—
Deferred	0	94	—
Total Income Taxes	(54)	94	—
Income (Loss) Before Extraordinary Item	(6,059)	182	(162,338)
Extraordinary Income (Loss) Forgiveness of Long-term Debt and Accrued Interest	—	—	293,723
Net Income (Loss)	$(6,059)	$ 182	$131,385

(The accompanying notes are an integral part of these statements.)

GREAT BAY POWER CORPORATION

STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(Dollars in Thousands)

	Common Stock, $.01 Par Value — Authorized, issued and outstanding 10,000 shares	Less: Treasury Stock, 10,000 shares	Paid-In Capital Treasury Stock	Total Common Stock	Common Stock, $.01 Par Value — Authorized, issued and outstanding 8,000,000 shares	Additional Paid-In Capital	Redeemable Preferred Stock	Retained Earnings	Total Stockholders' Equity
Predecessor									
Balance at December 31, 1993	$ 10	$(10)	$ 10	$ 10	$—	$ —	$ 63,090	$(139,793)	$(76,693)
Financial Results, January 1 to November 23, 1994 ...	—	—	—		—	—	—	127,789	127,789
Equity Infusion and Fresh-Start Adj's	(10)	10	(10)	(10)	80	88,030	(63,090)	12,004	37,014
Successor									
Balance at November 23, 1994	—	—	—		80	88,030	—	—	88,110
Financial Results, November 24 to December 31, 1994 ...	—	—	—		—	—	—	182	182
Balance at December 31, 1994	—	—	—		80	88,030	—	182	88,292
Financial Results, January 1 to December 31, 1995 ...	—	—	—		—	—	—	(6,059)	(6,059)
Balance at December 31, 1995	—	—	—		$80	$88,030	—	$ (5,877)	$ 82,233

(The accompanying notes are an integral part of these statements.)

GREAT BAY POWER CORPORATION

STATEMENT OF CASH FLOWS
(Dollars in Thousands)

	Successor: January 1 to December 31, 1995	Successor: November 24 to December 31, 1994	Predecessor: January 1 to November 23, 1994
Net cash flow from operating activities:			
Net Income	$ (6,059)	$ 182	$131,385
Adjustments to reconcile net earnings to net cash provided by (used in) operating activities:			
Depreciation	3,339	240	5,092
Amortization of nuclear fuel	4,520	553	3,571
Deferred income taxes	(94)	94	—
Writedown of assets, net	7[illegible]	—	137,908
Gain on forgiveness of debt	—	—	(293,723)
Gain on transfer of assets	(193)	—	—
Provision for reorganization expenses	—	—	4,038
Payment of reorganization expenses	(2,653)	(1,518)	—
(Increase) decrease in accounts receivable	1,021	(635)	507
Decrease in materials & supplies	113	39	201
(Increase) decrease in prepaids and other assets	1,718	(520)	1,631
Increase (decrease) in accounts payable	(66)	293	(81)
Increase in taxes accrued	126	273	312
Increase in misc. current liabilities		400	946
Other	183	261	717
et cash provided by (used in) operating activities	2,713	(358)	(7,496)
et cash flows (used in) investing activities:			
Utility plant additions	(1,770)	(260)	(1,774)
Nuclear fuel additions	(5,703)	—	(361)
Payments to decommissioning fund	(988)	(98)	(830)
Short term investments, net	(3,911)	(3,684)	—
et cash used in investing activities	(12,372)	(4,042)	(2,965)
et cash provided by financing activities:			
Sale of common stock	—	—	35,000
Borrowings under DIP financing	—	—	8,823
Repayment of DIP financing	—	—	(10,567)
t cash provided by financing activities	—	—	33,256
t (decrease) increase in cash and cash equivalents	(9,659)	(4,400)	22,795
sh and cash equivalents, beginning of period	18,533	22,933	138
sh and cash equivalents, end of period	$ 8,874	$18,533	$ 22,933

(The accompanying notes are an integral part of these statements.)

GREAT BAY POWER CORPORATION

NOTES TO FINANCIAL STATEMENTS
December 31, 1995

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. The Company

The Company, Great Bay Power Corporation, is a New Hampshire corporation, which emerged from bankruptcy on November 23, 1994. The Predecessor Company, EUA Power Corporation ("The Predecessor") was incorporated in 1986. The Company is authorized by the New Hampshire Public Utilities Commission ("NHPUC") to engage in business as a public utility for the purposes of participating as a joint owner in the Seabrook Project, acquiring its 12.1% interest in the Seabrook Project and selling its share of the output of Seabrook Unit 1 for resale. The Seabrook Project is a nuclear-fueled, steam electricity, generating plant located in Seabrook, New Hampshire, which was originally planned to have two Westinghouse pressurized water reactors, Seabrook Unit 1 and Seabrook Unit 2 (each with a rated capacity of 1,150 megawatts), utilizing ocean water for condenser cooling purposes. Seabrook Unit 1 entered commercial service on August 19, 1990. Seabrook Unit 2 has been canceled. The Company became a wholesale generating company when Seabrook Unit 1 commenced commercial operation on August 19, 1990. In 1993, the Company became an Exempt Wholesale Generator ("EWG") under the Energy Policy Act of 1992.

The Company is required to pay its share (i.e., the same percentage as the percentage of its ownership and its entitlement to the output) of all of the costs of the Seabrook Project, including fixed costs (whether or not Seabrook Unit 1 is operating), operating costs, costs of additional construction or modification, costs associated with condemnation, shutdown, retirement, or decommissioning of the Seabrook Project, and certain transmission charges. The Predecessor never reported an operating profit from the time of its incorporation until it filed for bankruptcy in 1991. See Footnote 1B for further discussion. The Company's current business strategy is to seek purchasers for its share of the Seabrook Project electricity output at prices, either in the short term market or pursuant to medium or long term contracts, in excess of the prices currently available in the short term wholesale electricity market since sales at current short term rates do not result in sufficient revenue to enable the Company to meet its long term cash requirements for operations, maintenance and capital related costs. The Company's ability to obtain such higher prices will depend on regional, national and worldwide energy supply and demand factors.

The Company currently has two employees and substantially all the Company's power marketing and administrative functions for 1995 were performed on the Company's behalf by third parties pursuant to contractual agreements. See Notes 7 and 8 for further discussion of these agreements.

B. Bankruptcy Proceeding and Reorganization

The Company filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code ("the Bankruptcy Code") in the United States Bankruptcy Court for the District of New Hampshire ("the Bankruptcy Court") on February 28, 1991. It conducted its business as a Debtor in Possession until November 23, 1994, at which time the Company's First Amendment to the First Modified Plan dated September 9, 1994 ("the Amended Plan") became effective and the Company emerged from Chapter 11.

The Bankruptcy Court confirmed the Bondholders' Committee's Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Predecessor was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders' Committee obtained a commitment from Omega Advisers, Inc. ("Omega") or its designees to provide $35 million of equity financing for the Company (the "Financing").

On April 7, 1994, the Company and the Bondholders' Committee entered into a definitive Stock and Subscription Agreement (the "Stock and Subscription Agreement") with Omega and Elliott Associates, L.P. (Elliott) (collectively, the Investors) with respect to the Omega Financing.

The Bondholders' Committee prepared a First Modification to the Fifth Amended Plan of Reorganization to reflect the change from debt to equity financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Fifth Amended Plan of Reorganization, as modified by the First Modification, is hereinafter referred to as the "Plan." The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan was mailed to the Company's creditors for their approval on April 7, 1994, and the creditors approved the Plan by a significant margin.

On May 23, 1994, the Bankruptcy Court confirmed the Plan. The only condition which remained to be satisfied for the occurrence of the Effective Date of the Plan was the closing of the Stock and Subscription Agreement. The Committee believed that all of the conditions to closing set forth in the Stock and Subscription Agreement had been satisfied and was prepared to close the Stock and Subscription Agreement. Before the closing could occur, however, the operators of the Seabrook Project determined, during a regularly scheduled refueling outage, that certain repairs to the Seabrook Project were required. These repairs have been completed and the Seabrook Project is now operating. The repairs, however, caused the Seabrook Project to be out of service for approximately eight weeks longer than anticipated in connection with the scheduled refueling outage.

Because of the unplanned extension of the outage, the repairs required, and the related loss of revenue of the Company, Omega and Elliott asserted that a material adverse event had occurred with respect to the Company and that, therefore, they were not obligated to complete the Omega Financing. The Company disagreed with those assertions, and informed Omega and Elliott that they were in default under the Stock and Subscription Agreement and informed Omega and Elliott that the Company would bring suit to enforce the obligations of Omega and Elliott to close the Omega Financing. Notwithstanding its position on this matter, the Company engaged in negotiations with Omega and Elliott to settle the dispute and to complete the Omega Financing. On September 9, 1994, the Company, Omega and Elliott resolved their disputes and entered into a Settlement Agreement (the "Settlement Agreement").

The terms of the Settlement Agreement changed the terms of the Omega Financing. As described above, under the Plan before its amendment, the Investors were to receive 4.8 million shares, representing 60% of the common stock of the Company, in exchange for their \$35 million investment. The Settlement Agreement changed the Plan to provide also that, on the Effective Date of the Amended Plan, 480,000 shares of new common stock of the Company, which would have otherwise been distributed to the creditors of the Company, would be issued to the Disbursing Agent under the Plan (the "Escrow Shares"). The Escrow Shares represent 6% of the common stock of the Company. The Company's creditors received the remaining 34% on the Effective Date of the amended Plan.

On the first anniversary of the Effective Date of the Amended Plan, if the Aggregate Value, as defined in the Settlement Agreement, of the Purchasers' 4.8 million shares of common stock was less than \$38.5 million, the Company would be obligated to pay to the Investors an amount (the "True-Up Amount") equal to the lesser of (a) \$38.5 million less the Aggregate Value, or (b) the total value of all of the Escrow Shares, based on their per share value. The Settlement Agreement permitted the Investors to elect to have their True-Up amounts, if any, satisfied by the issuance of Escrow Shares or in cash. If the Aggregate Value was equal to or greater than \$38.5 million, the Escrow Shares would be issued on a pro rata basis to the Company's creditors in accordance with the Amended Plan. In no event, however, would the Investors be entitled to more than the 480,000 Escrow Shares, or the cash proceeds from the sale of those shares. On the first anniversary date, November 23, 1995, the Aggregate Value of the escrow shares was greater than \$38.5 million and they were issued to the creditors.

Pursuant to the Settlement Agreement, the Company amended the Plan and its related Disclosure Statement, submitted the Amended Plan and the Amended Disclosure Statement to the Bankruptcy Court for its approval and obtained that approval, circulated the Amended Plan and the Amended Disclosure Statement to the Company's creditors in order to give them the opportunity to change their previous votes approving the Plan, and then applied to the Bankruptcy Court for confirmation of the Amended Plan. The Bankruptcy Court confirmed the Amended Plan on November 4, 1994. In addition, the Company obtained extensions of time and, in some cases, reapprovals, from certain regulatory agencies which had previously approved the Omega Financing. Closing of the Omega Financing occurred on November 23, 1994, at which time the Company's First Amendment to the First Modified Plan dated September 9, 1994 ("the Amended Plan") became effective and the Company emerged from Chapter 11.

In accordance with Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code", the historical amounts of individual assets and liabilities have been adjusted to fair values and Liabilities Subject to Compromise of $293,864,000 have been discharged as a result of the Reorganization Plan. The amount of prior retained deficit eliminated as a result of the reorganization was $159,659,000. The reorganizational value has been determined based on the fair value of the Company (See Note 1D). The adjustments to individual assets and liabilities are as follows:

	Adjustments (In Thousands)
Writedown of Net Utility Plant and Nuclear Fuel	$ 193,635
Writedown of Deferred Debits	27,470
Recognition of Decommissioning Liability, net	45,193
Writedown of Deferred Taxes and ITC	(73,927)
Writedown of Deferred Gains and Credits	(47,375)
Other, net	(7,088)
Net Writedown of Assets	$ 137,908
Forgiveness of Liabilities Subject to Compromise	(293,864)
Recognition of Reorganization Expenses	4,038
Net adjustment to assets and liabilities	$(151,918)

The following unaudited proforma condensed statement of (loss) income is presented to illustrate the estimated effect of the reorganization as if such transaction had occurred as of January 1, 1994.

	Year Ended December 31, 1994	Proforma Adjustments	Proforma Year Ended December 31, 1994
Operating Revenues	$ 17,118		$ 17,118
Operating Expenses:			
Production & Transmission	19,631	$ (2,830) (f)	16,801
Administrative & General	4,540	700 (e)	5,240
Depreciation & Amortization	8,267	(5,461) (d)	2,806
Taxes Other than Income	4,280		4,280
Total Operating Expenses	36,718		29,127
Operating Income	(19,600)		(12,009)
Write down of Assets, net	137,908	(137,908) (a)	0
Reorganization Expenses	4,038	(4,038) (b)	0
Other Income	(101)		(101)
Interest Charges, net	617	(706) (c)	(89)
Net Loss Before Taxes	(162,062)		(11,819)
Income Taxes	94	(4,096) (g)	(4,002)
Net Loss before Extraordinary Item	(162,156)		(7,817)
Forgiveness of Debt	293,723	(293,723) (c)	0
Net Income (Loss)	$ 131,567		$ (7,817)

(a) Elimination of Writedown of Assets, Net

(b) Elimination of Reorganization Expenses

(c) Elimination of Forgiveness of Debt and related interest

(d) Depreciation expense adjusted to reflect asset writedown

(e) Additional expenses associated with UNITIL and Tillinghast agreements

(f) Recognition of new outage accrual policy

(g) Tax impact of above entries assuming ability to fully benefit loss

C. Regulation

The Company is subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC"), the Nuclear Regulatory Commission ("NRC") and the New Hampshire Public Utilities Commission ("NHPUC") and other federal and state agencies as to rates, operations and other matters. The Company's cost of service is not regulated. As such, the Company's accounting policies are not subject to the provisions of Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation".

D. Use of Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

E. Utility Plant

Utility plant at November 23, 1994 was revalued to its estimated fair value based on the fair value of the Company. The reorganization value of the Company at November 23, 1994 was determined based on discounted cash flow valuation. The cost of additions to utility plant subsequent to November 23, 1994 are recorded at original cost. During the period from January 1, 1994 to November 23, 1994, the Predecessor capitalized $121,000 of interest related to plant additions.

F. Depreciation and Maintenance

Electric plant is depreciated on the straight-line method at rates designed to fully depreciate all depreciable properties over the lesser of estimated useful lives or the Plant's remaining NRC license life, which extends to 2026.

Capital projects constituting retirement units are charged to electric plant. Minor repairs are charged to maintenance expense. When properties are retired, the original cost, plus cost of removal, less salvage, are charged to the accumulated provision for depreciation.

G. Amortization of Nuclear Fuel

The cost of nuclear fuel is amortized to expense based on the rate of burn-up of the assemblies comprising the total core. The Company also provides for the cost of disposing of spent nuclear fuel at rates specified by the United States Department of Energy ("DOE") under a contract for disposal between the Company and the DOE.

The Company amortizes to expense on a straight-line basis the estimated cost of the final unspent nuclear fuel core, which is expected to be in place at the expiration of the Plant's NRC operating license, in conformity with rates authorized by the FERC.

H. Amortization of Materials and Supplies

The Company amortizes to expense an amount designed to fully amortize the cost of the material and supplies inventory that is expected to be on hand at the expiration of the Plant's NRC operating license.

I. Decommissioning

Based on the Financial Accounting Standards Board's ("FASB") tentative conclusions, the Company has recognized as a liability its proportionate share of the estimated Seabrook Project decommissioning. The initial recognition of this liability was capitalized as part of the Fair Value of the Utility Plant at November 23, 1994. The estimated cost to decommission the Seabrook Project, based on a study performed for the lead owner of the Plant, is approximately $414 million in 1995 dollars and $2.1 billion in 2026 dollars and assumes a 36 year life for the facility and a future escalation rate of 4.25%. Based on this estimate, the Company's share in 1995 dollars is approximately $50.2 million, which has been recorded as a liability in the December 31, 1995 balance sheet.

The Seabrook project's decommissioning estimate and funding schedule is subject to review each year by the New Hampshire Nuclear Decommissioning Finance Committee ("NDFC"). This estimate is based on a number of assumptions. Changes in assumptions for such things as labor and material costs, technology, inflation and timing of decommissioning could cause these estimates to change in the near term. The review of the 1996 estimate and funding schedule by the NDFC is currently scheduled for May.

The Staff of the SEC has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations and joint owners in the financial statements of these entities. In response to these questions, the FASB has agreed to review the accounting for nuclear decommissioning costs. Although the Company's accounting for decommissioning was based on the FASB's tentative conclusions, if the accounting practices for nuclear power plant decommissioning are changed, the annual provision for decommissioning could change relative to 1995. The Company is uncertain as to the impact, if any, changes in the current accounting will have on the Company's financial statements.

Funds collected by Seabrook for Decommissioning are deposited in an external irrevocable trust pending their ultimate use. The earnings on the external trusts also accumulate in the fund balance. The trust funds are restricted for use in paying the decommissioning of Unit I. The investments in the trust are available for sale. The Company has therefore reported its investment in trust fund assets at market value.

Although the owners of Seabrook are accumulating funds in an external trust to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners, including the Company, would remain liable for the excess. The amount that is required to be deposited in the trust fund is subject to periodic review and adjustment by the NDFC, which could result in material increases in such amounts.

On November 15, 1992 , the Company, the Bondholder's Committee and the Predecessor's former parent, Eastern Utilities Associates (EUA) entered into a settlement agreement which resolved certain proceedings against EUA brought by the Bondholder's Committee. Under the settlement agreement EUA reaffirmed its guarantee of up to $10 million of the Company's future decommissioning costs of Seabrook Unit 1.

J. Operating Revenues

Revenues are recorded on an accrual basis based on billing rates provided for in contracts and approved by FERC.

K. Taxes on Income

The Company accounts for taxes on income under the liability method required by Statement of Financial Accounting Standards No. 109.

L. Cash Equivalents and Short Term Investments

For purposes of the Statements of Cash Flows, the Company considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents. The carrying amounts approximate fair value because of the short-term maturity of the investments.

All other short term investments with a maturity of greater than three months are classified as trading securities and reflected as a current asset at market value.

M. Seabrook Unit 2

The Company also has a 12.1% ownership interest in Seabrook Unit 2 to which it has assigned no value On November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been canceled, voted to dispose of the Unit. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties and or used in Seabrook Unit 1. Plans regarding disposition of Seabrook Unit 2 are now under consideration, but have not been finalized and approved. The Company is unable, therefore, to estimate the costs for which it would be responsible in connection with the disposition of Seabrook Unit 2. Monthly charges are required to be paid by the Company with respect to Seabrook Unit 2 in order to preserve and protect its components and various warranties. Any sales or transfers to Unit 1 of Unit 2 property or inventory are reflected in other income as gains on the sale or transfer of assets.

N. Seabrook Outage Costs

The Company's operating results and the comparability of these results on an interim and annual basis are directly impacted by the operations of the Seabrook Project, including the cyclical refueling outages (generally 18-24 months apart) as well as unscheduled outages. During outage periods at the Seabrook Project, the Company has no electricity for resale and consequently no revenues. Therefore the impact of outages on the Company's results of operations and financial position is materially adverse.

The Company accrues for the incremental costs of the Seabrook Project's scheduled outages over the periods between those outages. However, the Company continues to expense the normal Seabrook operating and maintenance expenses as incurred. Therefore, the Company will incur losses during scheduled outage periods as a result of the combination of the lack of revenue and the recognition of normal recurring operation and maintenance costs as well as the continuing depreciation of the Utility Plant. Based on expected fuel consumption, the Seabrook plant management has scheduled the next refueling outage for June 1997 at an estimated cost of $20 million. The Company's share is approximately $2.4 million. The estimate is based on a number of assumptions. Changes in assumptions for such things as labor and contractor costs, required repairs and days to perform the outage and plant operations in the interim, could cause this estimate to change in the near term.

2. NUCLEAR ISSUES

Like other nuclear generating facilities, the Seabrook Project is subject to extensive regulation by the NRC. The NRC is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health, safety, environmental and anti-trust matters.

The NRC has promulgated numerous requirements affecting safety systems, fire protection, emergency response planning and notification systems, and other aspects of nuclear plant construction, equipment and operation. The Company has been, and may be, affected to the extent of its proportionate share by the cost of any such modifications to Seabrook Unit 1.

Nuclear units in the United States have been subject to widespread criticism and opposition. Some nuclear projects have been canceled following substantial construction delays and cost overruns as the result of licensing problems, unanticipated construction defects and other difficulties. Various groups have by litigation, legislation and participation in administrative proceedings sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste. In the event of a shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. The cost of such decommissioning, depending on the circumstances, could substantially exceed the owners' investment at the time of cancellation.

Public controversy concerning nuclear power could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

A. Nuclear Fuel

The Seabrook Project's joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. The owners and lead participants of each United States nuclear unit have entered into contracts with the DOE for disposal of spent nuclear fuel, in accordance with the NWPA. The NWPA requires (subject to various contingencies) that the federal government design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such wastes and fuel. The NWPA specifies that the DOE provide for the disposal of such wastes and spent nuclear fuel starting in 1998.

Objections on environmental and other grounds have been asserted against proposals for storage as well as disposal of spent fuel. The DOE anticipates that a permanent disposal site for spent fuel will be ready to accept fuel for storage on or before the year 2010. However, the NRC, which must license the site, stated only that a permanent repository will become available by the year 2025. At the Seabrook Project, there is on-site storage capacity which, with minimal capital expenditures, should be sufficient for twenty years or until the year 2010. No near-term capital expenditures are anticipated to deal with any increase in storage requirements after 2010.

B. Federal Department of Energy ("DOE") Decontamination and Decommissioning Assessment

Title XI of the Energy Policy Act of 1992 (the "Policy Act") provides for decontaminating and decommissioning of the DOE's enrichment facilities to be partially funded by a special assessment against domestic utilities. Each utility's share of the assessment is to be based on its cumulative consumption of DOE enrichment services. As of December 31, 1995, the Company had accrued its pro rata estimated obligation of $738,000 related to the project's prior years' usage to be paid over the 15-year period beginning October 1, 1992.

C. Price Anderson Act

In accordance with the Price Anderson Act, the limit of liability for a nuclear-related accident is approximately $8.9 billion, effective November 18, 1994. The primary layer of insurance for this liability is $200 million of coverage provided by the commercial insurance market. The secondary coverage is approximately $8.7 billion, based on the 110 currently licensed reactors in the United States. The secondary layer is based on a retrospective premium assessment of $79.3 million per nuclear accident per licensed reactor, payable at a rate not exceeding $10 million per year per accident and a maximum of $20 million per year. In addition, the retrospective premium is subject to inflation based indexing at five year intervals and, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection available, then each licensee can be assessed an additional 5% ($3.775 million) of the maximum retrospective assessment. With respect to the Seabrook Project, the Company would be obligated to pay its ownership share of any assessment resulting from a nuclear incident at any United States nuclear generating facility. The Company estimates its maximum liability per incident currently would be an aggregate amount of approximately $9.59 million per accident, with a maximum annual assessment of about $1.21 million per incident, per year.

In addition to the insurance required by the Price Anderson Act, the NRC regulations require licensees, including the Seabrook Project, to carry all risk nuclear property damage insurance in the amount of at least $1.06 billion, which amount must be dedicated, in the event of an accident at the reactor, to the stabilization and decontamination of the reactor to prevent significant risk to the public health and safety.

D. Nuclear Insurance

Insurance has been purchased by the Seabrook Project from Nuclear Electric Insurance Limited ("NEIL") to cover the costs of property damage, decontamination or premature decommissioning resulting from a nuclear incident and American Nuclear Insurance/Mutual Atomic Energy Liability Underwriters

("ANI") to cover workers claims. All companies insured with NEIL and ANI are subject to retroactive assessments, if losses exceed the accumulated funds available to NEIL and ANI, respectively. The maximum potential assessment against the Seabrook Project with respect to losses arising during the current policy years are $26.4 million. The Company's liability for the retrospective premium adjustment for any policy year ceases six years after the end of that policy year unless prior demand has been made.

The Company purchased additional business interruption insurance from NEIL with the current policy in effect from December 22, 1995 until September 15, 1996. NEIL business interruption insurance is designed to pay a weekly indemnity in the event of a prolonged outage at Seabrook resulting from property damage occurring from a "sudden fortuitous event, which happens by chance, is unexpected and unforeseeable." The Company is seeking $520,000 of weekly indemnity with a limit of liability of $70.3 million. This policy has an annual premium of $129,000 and for the period ending December 31, 1995 the Company expensed $3,520 related to this policy. Under the terms of this policy, the Company is subject to a potential retrospective premium adjustment of $647,000 should NEIL's board of directors deem that additional funds are necessary to preserve the financial integrity of NEIL. There has never been a retrospective adjustment since NEIL was founded in 1980. The liability for this retrospective premium adjustment ceases six years after the end of the policy unless prior demand has been made.

3. TAXES ON INCOME

The following is a summary of the (benefit) provision for income taxes for the year ended December 31, 1995, the period from November 24 to December 31, 1994, and the period from January 1 to November 23, 1994:

	Successor		Predecessor
		November 24 to December 31,	January 1 to November 23,
	1995	1994	1994
		(000's)	
Federal			
Current	$(8,065)	$(353)	$(11,253)
Deferred	8,011	447	11,253
	(54)	94	—
State			
Current	(1,923)	(84)	(2,684)
Deferred	1,923	84	2,684
	—	—	—
Total (benefit) provision	$ (54)	$ 94	$ —

Accumulated deferred income taxes consisted of the following at December 31, 1995 and 1994:

	1995	1994
	(000's)	
Assets		
Net operating loss carryforwards	$64,957	$54,472
Decommissioning expense	618	325
Utility plant	—	1,009
Unfunded pension expense	225	102
Accrued outage expense	43	84
Inventory	196	—
Liabilities		
Utility plant	(7,250)	—
Accumulated deferred income tax asset	58,789	55,992
Valuation allowance	(58,789)	(56,086)
Accumulated deferred income tax asset (liability) net	$ —	$ (94)

The total income tax provision set forth above represents 0% in the year ended 1995, 34% in the period from November 24 to December 31, 1994 and 0% in the period from January 1, 1994 to November 23, 1994 of income before such taxes. The following table reconciles the statutory federal income tax rate to those percentages:

	Successor		Predecessor
		November 24 to December 31,	January 1 to November 23,
	1995	1994	1994
	(Dollars in Thousands)		
(Loss) Income before taxes	$(6,113)	$276	$131,385
Federal statutory rate	34%	34%	34%
Federal income tax (benefit) expense at statutory levels	(2,078)	94	44,671
Increase (Decrease) from statutory levels			
State tax net of federal tax benefit	(1,269)	(55)	(913)
Valuation allowance	2,703	49	858
Income of decommissioning trust	305	6	55
Benefit from reorganization	—	—	(44,671)
Other	285	—	—
Effective federal income tax expense	$ (54)	$ 94	$ —

Valuation allowances have been provided against any deferred tax assets, net due to the limitations on the use of carryforwards, discussed below and the uncertainty associated with future taxable income. The valuation allowance of $56,086,000 as of December 31, 1994, if subsequently recognized will be allocated directly to paid in capital.

As of December 31, 1995, the Company has an estimated $167 million in net operating loss carryforwards ("NOL's") that expire between the years 2005 to 2010. However, because the Company has experienced one or more ownership changes, within the meaning of Section 382 of the Internal Revenue Code of 1986, as amended (the "Tax Code"), an annual limitation has been imposed on the ability of the Company to use $136 million of these carryforwards. The Company's best estimate at this time is that the annual limitation is approximately $5.5 million, and therefore, the ability to use $136 million in NOL's is restricted.

4. COMMON STOCK RESTRICTIONS

The Company has never paid cash dividends on the Common Stock. The Company currently expects that it will retain all of its future earnings and does not anticipate paying a dividend in the foreseeable future.

5. CAPITAL EXPENDITURES

The Company's cash construction expenditures, including nuclear fuel, are estimated to be approximately $2.7 million in 1996 and to aggregate approximately $21.5 million for the years 1997 through 2000.

6. UNITIL POWER PURCHASE AGREEMENT AND POWER PURCHASE OPTION

The Company has entered into an agreement (the "Power Purchase Agreement"), dated as of April 1, 1993 with UNITIL Power Corporation ("UNITIL Power"), a wholly owned subsidiary of UNITIL Corporation ("UNITIL"), which provides for the Company to sell to UNITIL Power approximately 10MW of power. The Power Purchase Agreement commenced on May 1, 1993 and runs through October 31, 2010. During the first year, the price of power under the Power Purchase Agreement was 5.0 cents per kilowatt hour (kWh). Thereafter, the price is subject to increase in accordance with a formula which provides for adjustments at less than the actual rate of inflation. UNITIL Power has the option to extend the Power Purchase Agreement for an additional twelve years to 2022.

The Power Purchase Agreement is front-end loaded whereby UNITIL Power pays higher prices, on an inflation adjusted basis, in the early years of the Agreement and lower prices in later years. The average price per kWh and the contract formula rate in the contract are fixed over the life of the contract, so that any excess cash received in the beginning of the contract will be returned by the end of the contract, provided the contract does not terminate early. The difference between revenue billed under each rate is recorded in a "Balance Account" which increases annually to $4.1 million in 1998, then decreases annually, reaching zero in 2001. Therefore, contract revenue is recorded under Generally Accepted Accounting Principles and Emerging Issues Task Force Ruling 91-6 based on the contract rates and no liability for the "Balance Account" is recognized provided that it is not probable that the contract will terminate early. Management believes it is not probable that either party will terminate this contract prior to the end of its initial term. The balance in the balance account as of December 31, 1995 is approximately $2.0 million.

To secure the obligation of the Company under the Power Purchase Agreement and to repay to UNITIL Power the amounts in the balance account, if the contract terminates early, the Power Purchase Agreement grants UNITIL Power a mortgage on the Company's Seabrook Interest. This mortgage granted to UNITIL Power is junior only to the existing mortgage on the Seabrook Interest granted pursuant to the Third Stipulation and any successor first mortgage financing up to a maximum amount of $80,000,000. The Power Purchase Agreement further provides that UNITIL Power's second mortgage will rank pari passu with other mortgages that may hereafter be granted to other purchasers of power from the Company to secure similar obligations, provided that the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest does not exceed $60,000,000, and provided that the combined total of all second mortgages on the Seabrook Interest does not exceed the sum of (a) $80,000,000 less the total amount of the Company's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

In addition to the Power Purchase Agreement, the Company also has entered into an agreement (the "Power Purchase Option Agreement") with UNITIL Power under which the Company will grant UNITIL Power the option to purchase during the period from November 1, 1998 through October 31, 2018, approximately 15MW of electricity at 6.5 cents per kWh, subject to adjustment in accordance with a formula. UNITIL Power will be required to exercise its option under the Power Purchase Option Agreement on or before the earlier of (a) October 31, 1996, and (b) 30 days after the first date on which the Company is prepared to commit to sell, for a minimum of 10 years, all or any part of the last remaining 15 MW of electricity from Seabrook Unit 1 to which the Company is entitled.

7. PECO SERVICES AGREEMENT AND WARRANT AGREEMENT

The Company has entered into a Services Agreement (the "Services Agreement"), dated November 3, 1995 with PECO Energy Company (PECO). As exclusive agent for the Company, PECO will market the Company's approximately 130MW of uncommitted capacity generated by Great Bay Power's 12% ownership in the Seabrook Nuclear Power Plant. The Services Agreement commenced on November 3, 1995 and runs through December 31, 1997. PECO pays the Company a reservation fee based on the hours during which Seabrook generates energy. The Company pays PECO a service fee based on net revenues and a Seabrook operating capacity factor. This service from PECO is expected to permit the Company to compete more effectively for firm, all requirements power contracts. The arrangement also provides for the Company and PECO to jointly pursue other opportunities which are intended to maximize the value of the Company's interest in Seabrook.

The Company entered into another agreement with PECO, also dated November 3, 1995, whereby PECO agreed to purchase a warrant from the Company for $1,000,000. The warrant grants to PECO the right to purchase 420,000 shares of the Company's $.01 par value common stock (4.99% of the total shares outstanding) at an exercise price of the higher of (1) $9.7: per share, or (2) the highest trading price per share of the Company's common stock prior to the expiration date. The purchase price for the warrant will be credited toward the purchase price for the shares upon exercise of the warrant. The warrant expires on September 30, 1996 unless extended because the Seabrook facility fails to maintain a 60% capacity factor for the first 9 months of 1996, in which case the expiration date is extended until the earlier of such time as Seabrook's rolling 12-month capacity factor equals or exceeds 60% or December 31, 1997. If PECO exercises the warrant to acquire 4.99% of the Company, the marketing agreement will be extended to December 31, 1998.

8. TRANSACTIONS WITH RELATED PARTIES

The Company entered into two other agreements with affiliates of UNITIL.

A Management and Administrative Services Agreement was in effect during 1995 between the Company and UNITIL Resources, Inc. ("UNITIL Resources"), a wholly owned subsidiary of UNITIL until December 31, 1995. The Management and Administrative Services Agreement went into effect on November 23, 1994 and provided for UNITIL Resources to provide a full range of services to the Company, including management, accounting and bookkeeping, budgeting and regulatory compliance. Under the Management and Administrative Services Agreement, the Company was paying UNITIL Resources $225,000 per year for senior executive management services and was paying for day-to-day operational services by paying an amount equal to the cost of providing those services plus 25% of such cost. For the year ended December 31, 1995 and for the period from November 24, 1994 to December 31, 1994, the Company expensed $591,352 and $52,900 respectively related to this agreement. The Management and Administrative Services Agreement had an automatically renewing one year term, except that either the Company or UNITIL Resources may terminate without cause on 60 days prior written notice. The Company gave notice and terminated this agreement on December 31, 1995.

The Company's marketing efforts were provided by UNITIL Resources until December 31, 1995. Under the terms of this Marketing Agreement with UNITIL Resources, the Company was paying UNITIL Resources all costs incurred by UNITIL Resources to obtain new sales contracts plus a commission for sales of power. The amount of the commission payable varied based on the length of the power sale contracts and prices obtained. For the year ended December 31, 1995 and for the period from November 24, 1994 to

December 31, 1994, the Company expensed $333,138 and $11,500, respectively, related to this agreement. This agreement was also terminated as of December 31, 1995.

The Company leases its headquarters space under an expense sharing agreement with TILTEC, a company owned by the Company's President. Under the agreement, TILTEC provides the Company with furnished office space and administrative support services for a total fee of $7,400 per month. The expense sharing agreement has a one year term and provides for automatic one year renewals. Either party may terminate the agreement on 60 days prior written notice to the other party.

Prior to February 5, 1993, the Predecessor was a wholly-owned subsidiary of EUA. EUA has interests in other retail and wholesale utility companies, a service corporation, and other non-utility companies. Transactions between the Predecessor and EUA affiliated companies prior to the reorganization include accounting, engineering and other services rendered by EUA Service of approximately $116,000 for the period from January 1, 1994 to November 23, 1994.

9. STOCK OPTION PLAN

On April 24, 1995, the Board of Directors of the Company established the 1995 Stock Option Plan (the "Plan"), subject to shareholder approval. The purpose of the Plan is to secure for the Company and its shareholders the benefits arising from capital stock ownership by employees, officers and directors of, and consultants or advisors to, the Company who are expected to contribute to the Company's future growth and success. Options granted pursuant to the Plan may be either incentive stock options meeting the requirements of Section 422 of the Internal Revenue Code or non-statutory options which are not intended to meet the requirements of Section 422. The maximum number of shares of Common Stock which may be issued and sold under the Plan is 600,000 shares. The Plan will be administered by the Board of Directors of the Company and may be modified or amended by the Board in any respect, subject to shareholder approval in certain instances. Shareholder approval of the Plan has not yet been sought or obtained. The Company expects the Plan to be approved by shareholders at the Company's annual meeting scheduled to be held in April 1996.

To date, the following options have been granted under the Plan:

	Number of Shares	Average Option Price
1995 Activity		
Granted	335,000	8.17
Exercised	—	—
Canceled	—	—
Outstanding at December 31, 1995	335,000	

10. NEW ACCOUNTING PRONOUNCEMENTS

In March 1995, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed Of", effective for fiscal years beginning after December 15, 1995. SFAS No. 121 establishes accounting standards for the impairment of long-lived assets and requires that assets which are no longer probable of recovery be charged to earnings. The Company adopted SFAS No. 121 on January 1, 1996, and the adoption did not have a material impact on the Company's financial position or results of operations.

In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation", effective for fiscal years beginning after December 15, 1995. SFAS No. 123 requires that financial statements include certain disclosures related to stock-based employee compensation arrangements regardless of the method used to account for them. The Company does not plan to adopt the accounting under this pronouncement but rather adopt the required audited pro forma disclosure. Based on arrangements used by the pronouncement, the pro forma effects on earnings and earnings per share are not expected to be material.

11. PROPERTY TAXES

In December 1995, the Town of Seabrook, New Hampshire (the "Town") issued a bill for property taxes for the second half of 1995 to "North Atlantic Energy Corp., et al." The Town informed the Company that it believed the Company's share of this bill was equal to $1,293,000. The Company has refused to pay the bill because the Company believes that the Town's assessment of the Company's interest in the Seabrook Project is greatly overstated and because the bill fails to recognize the Company as an independent taxpayer with a separately assessed and valued parcel of real estate. While the Company refused to pay the December property tax bill, the Company has accrued the $1,293,000 related to the bill. No litigation resulting from the Company's refusal to pay such tax bill is pending, but the Town has available to it a variety of remedies for the nonpayment of taxes, including placing a lien on the property. Management is unable to express an opinion as to the likely outcome of this matter.

12. SUBSEQUENT EVENTS

On January 18, 1996, the Company held a special meeting of stockholders. At the special meeting, the stockholders approved the following amendments to the Company's Restated Articles of Incorporation: (1) the number of authorized shares of common stock was increased from 8,000,000 to 20,000,000 shares; (2) 5,000,000 shares of undesignated Preferred Stock were authorized, the terms and rights of which may be designated from time to time by the Board of Directors; (3) a provision requiring the affirmative vote of the holders of at least 75% of the shares of capital stock issued and outstanding to amend, repeal or adopt any provision inconsistent with the Articles of Incorporation was deleted; and (4) a provision eliminating any preemptive rights of the Company's stockholders to acquire shares issued by the Company was added.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Director of Great Bay Power Corporation:

We have audited the statements of loss and retained (deficit) earnings and cash flows for the year ended December 31, 1993 of Great Bay Power Corporation (formerly EUA Power Corporation; the "Company"). These financial statements are the responsibility of the Company's management. Our responsibility is to express our opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the results of operations and cash flows of the Company for the year ended December 31, 1993 in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

Boston, Massachusetts
April 7, 1994, except as to the
information presented in
Note I. for which the date is
November 23, 1994

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)

STATEMENT OF LOSS
December 31, 1993
(Debtor-in-Possession) (In Thousands)

Operating Revenues	$24,620
Operating Expenses:	
Fuel	6,869
Other Operation	13,052
Maintenance	3,070
Depreciation and Decommissioning	9,020
Taxes Other Than Income	3,878
Income Tax (Credit)	(630)
Deferred Taxes (Credit)	(3,421)
Total Operating Expenses	31,838
Operating (Loss)	(7,218)
Deferred Income Taxes	(459)
Other Income — Net	226
Reorganization Expenses	1,867
Income Before Interest Charges	(9,318)
Interest Charges:	
Interest on Long-Term Debt (Contractual Interest Expense for 1993 was $48,929,510)	
Other Interest Expense (Contractual Interest Expense for 1993 was $144,763)	115
Net Interest Charges (Deductions)	115
Net Loss	$(9,433)

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)

STATEMENT OF RETAINED (DEFICIT) EARNINGS
Years Ended December 31, 1993
(Debtor-in-Possession) (In Thousands)

Retained (Deficit) Earnings — Beginning of Year	$(130,360)
Net Loss	(9,433)
Retained (Deficit) Earnings — End of Year	$(139,793)

Note 1 — Other than the changes to Retained Earnings resulting from the Net Loss of $9,433,000, there was no change in the Equity of the Company during the year ended December 31, 1993.

(The accompanying notes are an integral part of these statements.)

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)

STATEMENTS OF CASH FLOW
December 31, 1993
(Debtor-in-Possession) (In Thousands)

Cash Flow From Operating Activities:	
Net Loss	$(9,433)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:	
Depreciation and Amortization	8,124
Amortization of Nuclear Fuel	5,818
Deferred Taxes	(2,962)
Investment Tax Credit, Net	(630)
Other — Net	1,026
Net Changes of Working Capital:	
Accounts Receivable	(97)
Accounts Payable	(122)
Accrued Taxes	139
Other — Net	(1,401)
Net Cash (Used In) Provided from Operating Activities	452
Cash Flow From Investing Activities:	
Construction Expenditures	(6,885)
Net Cash (Used In) Provided From Investing Activities	(6,885)
Cash Flow From Financing Activities:	
Issuances:	
Debtor-in-Possession Financing	1,744
Settlement Proceeds	
Net Cash Provided from Financing Activities	1,744
Net Increase (Decrease) in Cash	(4,679)
Cash and Temporary Cash Investments at Beginning of Year	4,817
Cash and Temporary Cash Investments at End of Period	$ 138

(The accompanying notes are an integral part of these statements.)

Note A — Business:

The Registrant, Great Bay Power Corporation (formerly known as EUA Power Corporation), is a New Hampshire corporation, incorporated in 1986, authorized by the NHPUC to engage in business as a public utility for the purposes of participating as a joint owner in the Seabrook Project, acquiring its 12.1% interest in the Seabrook Project and selling its share of the output of Seabrook Unit 1 for resale. The Company, organized as a wholly-owned subsidiary of EUA, became fully independent of EUA on February 5, 1993 in connection with the bankruptcy proceeding described in Note B — Bankruptcy Proceeding. The Company became a wholesale generating company when Seabrook Unit 1 commenced commercial operation on August 19, 1990.

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Bondholders Committees' Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega Advisers, Inc. ("Omega") or its designees to provide $35 million of equity financing for the Company (the "Omega Financing"). The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Fifth Amended Plan of Reorganization, as modified by the First Modification is hereinafter referred to as the "Plan." The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. (See **Bankruptcy Proceeding** below for a discussion of the Company's bankruptcy proceeding and the Omega Financing.)

Seabrook Unit 1 is a 1,150 MW nuclear generating plant located in Seabrook, New Hampshire. The Company acquired its joint ownership interest in the Seabrook Project for approximately $174,000,000 in November 1986 from five New England electric utilities in independently negotiated transactions. At that time, construction of Seabrook Unit 1 was substantially completed. Because Seabrook Unit 2 had been canceled, the Company assigned no value to it. On March 29, 1991, the Company announced that it had provided an impairment reserve in 1990 against its investment in Seabrook Unit I, which was recorded effective on December 31, 1990. For financial statement reporting purposes, the Company valued its investment in Seabrook Unit I, including nuclear fuel but net of the related Series B and C Notes which it collateralizes as follows:

	December 31, 1990	December 31, 1993
	(In thousands)	
Net Investment	$ 340,640	$ 311,932
Related Secured Debt	(300,597)	(293,723) (1)
Net Carrying Amount	$ 40,043	$ 18,209

(1) includes accrued interest of $14,126

The ultimate value of the investment and the related debt (which is a liability subject to compromise) cannot be determined until the bankruptcy is resolved.

The Company has no employees. John R. Stevens, president of EUA serves as president and sole director of the Company at the request and subject to the direction of the Bondholders Committee. Mr. Stevens expects to resign both positions on the Effective Date. Since the Company's organization, EUA Service, a wholly owned subsidiary of EUA, has provided, or arranged for, various management and professional services. Pursuant to various Bankruptcy Court orders, EUA Service continues to provide similar services to the Company. Under the terms of the Settlement Agreement (as discussed below), EUA Service will continue to provide, at cost, certain services to the Company at the request of the Bondholders Committee for a period of not more than two years from the effective date of the Settlement Agreement. However, such services specifically exclude the marketing of the Company's entitlement in Seabrook Unit 1 on a long-term basis. The Company has agreed with UNITIL that an affiliate of UNITIL will replace EUA Service in providing various services on the Effective Date. In addition, the Company has entered into a contract with an affiliate of UNITIL pursuant to which that affiliate is marketing the Company's share of electricity from Seabrook Unit 1.

Note B — Bankruptcy Proceeding:

Background:

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the federal Bankruptcy Code and has been conducting its business as a Debtor and Debtor-in-Possession under the provisions of the Bankruptcy Code. The Company filed such petition because the cash generated by short-term sales of electricity from its entitlement in Seabrook Unit 1 would have been insufficient to pay interest on its outstanding Secured Notes when interest became due on May 15, 1991 and the prospects for signing long-term power sales contracts prior to that date were minimal. The Company continues its efforts to market its entitlement to Seabrook Unit 1 under the direction of the Bondholders Committee.

Settlement Agreement:

On November 18, 1992, the Company, the Bondholders Committee and EUA entered into a Settlement Agreement which resolved certain adversary proceedings against EUA, brought, or threatened to be brought, by the Bondholders Committee including, (i) a claim for recovery of certain alleged preferential transfers in the aggregate amount of $38.5 million, plus interest; (ii) a threatened claim for the recovery of $100 million plus treble damages arising from, among other things, certain alleged breaches of fiduciary duties by EUA, EUA Service and the officers and directors of the Company; and, (iii) certain matters arising out of tax sharing agreements between EUA, its subsidiaries, and the Company. The Settlement Agreement also provided for the payment of $20 million to the Company by EUA. The Settlement Agreement further provided for the relinquishment by EUA of its equity interest in the Company and all claims filed in Bankruptcy Court by EUA and its affiliates against the Company. These claims related primarily to obligations of the Company guaranteed and paid by EUA, including $21 million of Solid Waste Disposal Facility Revenue Bonds, issued by the New Hampshire Industrial Development Authority on behalf of the Company and other notes payable. The settlement of these claims was recorded as a deferred credit on the Company's 1992 Balance Sheet pending the ultimate outcome of the Bankruptcy Proceeding. The Settlement Agreement became effective on December 30, 1992 at which time EUA paid $20 million to the Company. The Company used a substantial portion of the proceeds from the Settlement Agreement to repay amounts outstanding under the First Stipulation (as described below) and to pay reorganization expenses and other operating expenses. The Company redeemed all of its outstanding equity securities which were held by EUA, at no cost, on February 5, 1993. The redeemed shares have been classified as treasury stock on the Company's financial statements as of December 31, 1993. As a result of the redemption, the Company is no longer part of the EUA System.

Under the Settlement Agreement, EUA reaffirmed its guarantee of up to $10 million of the Company's share of future decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. EUA had guaranteed this obligation in 1990 in order to secure the release to the Company of a $10 million fund established by the Company for the same purpose at the time the Company acquired its Seabrook Interest. Further, under the Settlement Agreement, all of the officers and directors of the Company (except Mr. Stevens) resigned and the Company changed its name to Great Bay Power Corporation. EUA now has no ownership interest in the Company.

Reorganization Plan:

The Bankruptcy Court confirmed the Bondholders Committees Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega or its designees to provide $35 million of equity financing for the Company. The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the Plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims pursuant to the Bonds and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. The holders of unsecured claims of less than $25,000, other than those unsecured claims resulting from the ownership of the Secured Notes, will be paid 50% of the amounts of their claims allowed by the Bankruptcy Court in cash on the Effective Date. The Plan requires that prior to the Effective Date the Bondholders Committee obtain the Omega Financing.

Although a bar date for all claims has been entered and passed, claims arising from the rejection of contracts or claims which the Bankruptcy Court permits to be filed notwithstanding the bar date may dilute the percentage of the unsecured claims held by the Secured Bondholders. All of the previously issued and outstanding equity securities of the Company have been redeemed by the Company. The CICs issued in connection with the Series B Notes or otherwise will be extinguished on the Effective Date. After the Effective Date, the equity of the Company will be represented by a single class of common stock. The Company will use good faith efforts to list its shares of common stock so that they will be tradeable on the American Stock Exchange or the NASDAQ National Market System.

The Bondholders Committee has appointed or will appoint agents to manage the Company's business and to market the Company's share of Seabrook electricity. During the period between the Confirmation of the Plan and the Effective Date, those agents are to report to the Bondholders Committee and, to the extent actions are to be taken outside of the ordinary course of business, such actions shall be subject to the approval of the Bankruptcy Court and regulatory bodies with jurisdiction under applicable law. John R. Stevens, president of EUA, expects to resign as president and director of the Company on the Effective Date. The Bondholders Committee has disclosed the names of two individuals proposed to serve on the Board of Directors (the New Board) of the Company after the Effective Date. The proposed two members of the New Board are John A. Tillinghast and Walter H. Goodenough. The Bondholders Committee is also considering other candidates to serve as members of the New Board. The persons who will serve on the New Board will be finally determined before the Effective Date. The New Board will take office upon the Effective Date. The New Board will serve until its members resign or are replaced in accordance with New Hampshire corporate law and the requirements of the Company's charter and by-laws.

The effectiveness of the Plan is conditioned upon obtaining plan of reorganization financing and approvals from various regulatory agencies including the NRC. The Company has obtained the approval of the NRC, provided the Company obtains plan of reorganization financing. The Company cannot predict whether it will be able to obtain plan of reorganization financing or whether the plan, or any other plan if filled, will be approved by the various regulatory agencies having jurisdiction

DIP Financing:

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses including, without limitation, operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA could adversely affect its entitlement in Unit 1. At current market prices, the cash generated by such electricity sales continues to be less than the Company's on-going cash requirements.

On August 29, 1991, the Bankruptcy Court approved a Stipulation and Consent Order (the First Stipulation) with respect to DIP Financing to be provided by certain joint owners of Seabrook for the benefit of the Company. The First Stipulation was entered into by the Company and CL&P and UI (the Participating Joint Owners), two of the other eleven joint owners of the Seabrook Project, as well as the Bondholders Committee. The First Stipulation was also approved by the NHPUC and the SEC under the 1935 Act.

On July 21, 1992, the Bankruptcy Court issued a procedural order permitting an extension of the First Stipulation. For the period after September 30, 1992 until March 5, 1993, the procedural order permitted continued debtor-in-possession financing on a month-to-month basis at the sole discretion of the Participating Joint Owners terminable on 30 days notice. The Bankruptcy Court issued a second procedural order on September 5, 1992 increasing to $22 million from $15 million the amount of advances outstanding at any one time permitted under the First Stipulation. The Participating Joint Owners continued to advance funds under the First Stipulation, as amended, until the amounts advanced thereunder were repaid with the proceeds of the Company's Settlement Agreement with EUA. The First Stipulation expired on March 5, 1993.

A second stipulation was entered into by the Company and the Participating Joint Owners and was approved by the Bankruptcy Court and various regulatory authorities. However, that stipulation did not become effective, and on March 5, 1993, the Company and the Participating Joint Owners entered into a third stipulation (the Third Stipulation) which was approved by the Bankruptcy Court.

The Third Stipulation provides that the Participating Joint Owners shall provide up to a maximum of $20 million in advances to the Company to enable the Company to pay its pro rata share of the Seabrook Project's operating expenses, expenses of the Company in connection with its Chapter 11 proceedings and certain other costs of operation of the Company. Pursuant to the Third Stipulation, the advances made by the Participating Joint Owners bear an interest rate equal to the prime rate of The First National Bank of Boston plus 7% per annum. The Third Stipulation provides the Participating Joint Owners with a priority lien on all the Company's assets, which lien has priority over the Bondholders' mortgage. The Third Stipulation further provides that in the event of a default thereunder, the Participating Joint Owners are entitled to purchase the Company's Seabrook Interest for 75% of the lesser of fair market value or book value and to apply all or part of the amounts owing under the Third Stipulation against the purchase price. The Third Stipulation terminates on the earliest to occur of (a) July 1, 1994, (b) the Effective Date or the closing of a sale of all or substantially all of the Company's assets or business, and (c) an event of default under the terms of the Third Stipulation. The Company is in default of the Third Stipulation for, among other reasons, failure to obtain financing for the Plan by the date required in the Third Stipulation. Although the Company has been in default since November 1, 1993, the Participating Joint Owners have continued to provide financing pursuant to the Third Stipulation. There is, however, no assurance that they will continue to do so. As of March 25, 1994, outstanding advances under the Third Stipulation were approximately $2.2 million in the aggregate.

Other Matters:

The Company's reorganization expenses are subject to approval by the Bankruptcy Court. For the period March 1, 1991 through August 31, 1993, professionals have submitted fees and expenses in the amount of approximately $5.9 million to the Bankruptcy Court for its approval, and the Bankruptcy Court has provisionally authorized, subject to its review at the conclusion of the Chapter 11 proceeding, payments of approximately $4.5 million. The Company has paid amounts provisionally authorized by the Bankruptcy Court, and those are reflected on the Company's Statement of Loss during the period in which they have been paid. Other submitted, but not provisionally authorized, expenses have not been recorded.

Since August 31, 1993, no hearings on approval of reorganization expenses have been held and no requests for allowance for such expenses have been made. According to the Supplemental Disclosure Statement, the Bondholders Committee has budgeted reorganization expenses payable on closing of the Omega Financing and subject to Bankruptcy Court approval of $4.5 million.

Under Chapter 11, certain claims against the Company in existence prior to the filing of the petition for relief under the Bankruptcy Code are stayed while the Company continues business operations as debtor-in-possession. These claims are reflected in the Company's Balance Sheet as of December 31, 1993 and December 31, 1992 as "Liabilities Subject to Compromise." Additional claims (Liabilities Subject to

Compromise) may arise subsequent to the filing date resulting from rejection of executory contracts and from the determination by the Bankruptcy Court (or agreed to by parties in interest) of allowed contingent and disputed claims. Enforcement of claims secured by certain of the Company's assets (secured claims) also are stayed, although the holders of such claims have the right to move the court for relief from the stay. Secured claims, principally the Secured Notes, are secured by an interest in certain Seabrook Project assets of the Company, principally realty and personalty.

Note C - Summary of Significant Accounting Policies:

System of Accounts: The accounting policies and practices of the Company are subject to regulation by FERC with respect to its rates and accounting. The accounts of the Company are maintained in accordance with the uniform system of accounts prescribed by FERC.

Utility Plant and Depreciation: Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and material, allocated overhead, allowance for funds used during construction and indirect charges for engineering and supervision. For financial statement purposes, depreciation is computed on the straight-line method based on the estimated useful life of Seabrook Unit 1. Since the commencement of commercial operation, the provision for depreciation for the Company has been calculated at 2.5%.

Operating Revenues: Revenues are based on billing rates authorized by FERC and are recognized when billed.

Income Taxes: The general policy of the Company with respect to accounting for federal income taxes is to reflect in income the estimated amount of taxes currently payable and to provide for deferred taxes on certain items subject to temporary differences to the extent permitted by the various regulatory commissions. It is the policy of the Company to defer the investment tax credits and to amortize these credits over the productive lives of the related assets.

Transactions With Affiliates: Prior to February 5, 1993, the Company was a wholly-owned subsidiary of EUA. EUA has interests in other retail and wholesale utility companies, a service corporation, and other non-utility companies.

Transactions between the Company and EUA affiliated companies include the following: accounting, engineering and other services rendered by EUA Service of approximately $209,000 in 1993. Transactions with other affiliated companies are subject to review by applicable regulatory commissions (See Note D — Income Taxes).

Cash and Temporary Cash Investments: The Company considers all highly liquid investments with a maturity of three months or less when acquired to be cash equivalents.

Note D — Income Taxes:

Components of income tax expense for the year 1993 is as follows:

	1993 (In thousands)
Federal:	
Current	$
Deferred	(3,421)
Investment Tax Credit, Net	(630)
Total Charge to Operations	(4,051)
Charged to Other Income:	
Current	
Deferred	459
Total charged to Other Income	459
Total	$(3,592)

Total income tax expense (credit) was different from the amounts computed by applying federal income tax at statutory rates to book income subject to tax for the following reasons:

	1993 (In thousands)
Federal Income Tax (FIT) Computed at Statutory Rates	$(4,559)
Increases (Decreases) in Tax from:	
Depreciation of Equity AFUDC	548
Amortization of ITC	(630)
FIT Net Operating Loss Carryforward	926
Nuclear Decommissioning Costs	313
Other	(190)
Total Income Tax Expense (Credit)	$(3,592)

The provision for deferred taxes resulting from temporary differences is comprised of the following:

	1993 (In thousands)
Debt Component of AFUDC	$(1,458)
Capitalized Overheads	(59)
Excess Tax Depreciation	7,181
Net Operating Loss Carryforward	(8,724)
Provision for Estimated Loss on Seabrook Investment	459
Other	(361)
Total	$(2,962)

The Company adopted FAS96 in 1990 which requires the use of the liability method to record deferred income taxes for temporary differences that are reported in different years for financial reporting and tax purposes. Under the liability method adopted by FAS96, deferred tax liabilities or assets are computed using the tax rates that will be in effect when the temporary differences reverse. Generally, for regulated companies, the changes in tax rates applied to accumulated deferred income taxes may not be immediately recognized in operating results because of rate making treatment and provisions in the Tax Reform Act of 1986.

The Company has filed consolidated income tax returns together with EUA and other EUA affiliates. As a result of such consolidated filings, certain federal income tax benefits available to the Company have reduced the federal income tax obligations of EUA and such other EUA affiliates. Under a tax allocation agreement between EUA and its subsidiaries, EUA and its subsidiaries compensate each other for the use of the tax benefits.

As a result of the redemption of the Company's outstanding common stock, the Company was deconsolidated from the EUA tax group effective February 5, 1993. Under the terms of the Settlement Agreement, EUA is entitled to utilize the Company's tax credits to reduce EUA's 1993 consolidated tax liability without compensation (see Note B - Bankruptcy Proceeding). The Company will be included in EUA's consolidated tax return for the years 1992 and 1993. However, the Company's net operating losses of approximately $25 million arising from its post February 5, 1993 activities will not be included in the EUA consolidated tax return for 1993, and have been treated as available to the Company.

To the extent that the Company's carryforwards of net operating losses, investment tax credits, alternative minimum tax credits, and deductions attributable to built in losses are available after the Company is no longer part of the consolidated return, the Company's ability to utilize these carryforwards will be significantly limited due to the impact of provisions of the tax law relating to the treatment of debt forgiveness in bankruptcy and the effect of changes in the ownership of the Company. The precise impact of these limitations cannot be determined until the Bankruptcy proceeding has concluded. In 1992, the Company reversed all accumulated tax benefits relating to carryforwards of net operating losses and alternative minimum tax credits to reflect the anticipated imposition of the limitations and the impact of the Settlement Agreement.

Note E — Capital Stock:

Common Stock: On December 31, 1993, the Company had issued and outstanding, no shares of its Common Stock, par value $.01.

Preferred Stock: At December 31, 1993, the Company had outstanding no shares of preferred stock.

Pursuant to the terms of the Settlement Agreements, on February 5, 1993 the Company redeemed all of its outstanding common and preferred stock, which were held by EUA, at no cost to the Company (See Note B — Bankruptcy Proceeding). The redemption has been classified as treasury stock on the Company's financial statements as of December 31, 1993.

Note F — Long-Term Debt:

As a result of the Bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued. The current face amount of principal, and accrued interest to February 28, 1991, on the Company's Secured Notes is $279,597,200 and $14,126,174 respectively. The Secured Notes are collateralized in part principally with a security interest in the Company's 12.1% ownership interest in the realty and personalty of the Seabrook Project. As a result of the bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued and ceased accruing interest expense as of February 28, 1991.

The contractual interest expense on the Secured Notes in 1993 was approximately $49 million. In 1993, no interest was paid. The Company also had outstanding 180,000 CICs evidencing the right to receive additional payments contingent upon and measured by the Company's income in certain years following the commercial operation of Seabrook Unit 1. Under the Plan, the CICs have been extinguished. (See Note B — Bankruptcy Proceeding)

The Secured Notes and CICs are solely the obligation of the Company and are not guaranteed by EUA or any other person.

The Series B Secured Notes, which have a stated maturity date of May 15, 1993, are redeemable at 100.125% of principal amount. The Series C Secured Notes have a stated maturity date of November 15, 1992.

GREAT BAY POWER CORPORATION

NOTES TO FINANCIAL STATEMENTS — (Continued)

December 31, 1993

Note G — Commitments and Contingencies:

Nuclear Power Issues

Like other nuclear generating facilities, the Seabrook Project is subject to extensive regulation by the NRC. The NRC is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health, safety, environmental and anti-trust matters. The NRC has promulgated numerous requirements affecting safety systems, fire protection, emergency response planning and notification systems, and other aspects of nuclear plant construction, equipment and operation. The Company has been, and may be, affected to the extent of its proportionate share by the cost of any such modifications to Seabrook Unit 1.

Nuclear units in the United States have been subject to widespread criticism and opposition. Some nuclear projects have been canceled following substantial construction delays and cost overruns as the result of licensing problems, unanticipated construction defects and other difficulties. Various groups have by litigation, legislation and participation in administrative proceedings sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste. In the event of shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. The cost of such decommissioning, depending on the circumstances, could substantially exceed the owners' investment at the time of cancellation.

Public controversy concerning nuclear power could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

The Price-Anderson Act provides, among other things, that the liability for damages resulting from a nuclear incident would not exceed an amount which at present is about $9.2 billion. Under the Price-Anderson Act, prior to operation of a nuclear reactor, the licensee is required to insure against this liability by purchasing the maximum amount of insurance available from private sources (currently $200 million) and to maintain the insurance available under a mandatory industry-wide retrospective rating program. Should an individual licensee's liability for an incident exceed $200 million, the difference between such liability and the overall maximum liability, currently about $9.2 billion, will be made up by the retrospective rating program. Under such a program, each owner of an operating nuclear facility may be assessed a retrospective premium of up to a limit of $79.3 million (which shall be adjusted for inflation at least every five years) for each reactor owned in the event of any one nuclear incident occurring at any reactor in the United States, with provision for payment of such assessment to be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. The Company would be obligated to pay its proportionate share of any such assessment.

Joint owners of nuclear projects are also subject to the risk that one of their number may be unable or unwilling to finance its share of the project's costs, thus jeopardizing continuation of the project. On May 6, 1991, New Hampshire Electric Cooperative, Inc., a 2.2% owner of the Seabrook Project, announced that it had filed for Chapter 11 bankruptcy protection. A reorganization plan, filed by the New Hampshire Electric Cooperative with the Bankruptcy Court in September, 1991 and revised in January, 1992 was approved by the Bankruptcy Court in March 1992 and approved by the NHPUC on October 5, 1992. All appeals of the NHPUC order approving the reorganization have been resolved in NHEC's favor and the effective date of the plan occurred on December 1, 1993.

Nuclear Fuel and Nuclear Plant Decommissioning:

The Seabrook Project joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. The owners and lead participants of United States nuclear units have entered into contracts with the DOE for disposal of spent nuclear fuel in accordance with the NWPA. The NWPA requires (subject to various contingencies) that the federal government design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such wastes and fuel. The NWPA specifies that the DOE provide for the disposal of such wastes and spent nuclear fuel starting in 1998. Objections on environmental and other grounds have been asserted against proposals for storage as well as disposal of spent fuel. The DOE anticipates that a permanent disposal site for spent fuel will be ready to accept fuel for storage on or before 2010. However, the NRC, which must license the site, stated only that a permanent repository will become available by the year 2025. At the Seabrook Project there is on-site storage capacity which, with minimal capital expenditures, should be sufficient for twenty years or until the year 2010. No near-term capital expenditures are anticipated to deal with any increase in storage requirements after 2010.

The estimated cost to decommission Seabrook Unit 1, based on a study by the New Hampshire Yankee Division of the Public Service Company of New Hampshire, is approximately $351 million in 1993 dollars. The Company's share of that amount is approximately $42.5 million, or 12.1%. In 1993, the Company paid approximately $895,000 in decommissioning expenses.

The agreements of purchase and sale under which the Company purchased its Seabrook interest required the Company to establish a fund of $10 million to secure payment of part of its share of decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. In May 1990, EUA guaranteed this obligation and the entire fund was released to EUA Power. Under the Settlement Agreement, EUA reaffirmed this guaranty.

Seabrook Unit 2:

The Company also has a 12.1% ownership interest in Seabrook Unit 2 in which it has assigned no value. On November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been canceled, voted to dispose of the Unit. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. Plans regarding disposition of Seabrook Unit 2 are now under consideration, but have not been finalized and approved. The Company is unable, therefore, to estimate the costs for which it would be responsible in connection with the disposition of Seabrook Unit 2. Monthly charges are required to be paid by the Company with respect to Seabrook Unit 2 in order to preserve and protect its components and various warranties.

Construction Expenditures

Great Bay Power's cash construction expenditures, including nuclear fuel, are estimated to be approximately $4.3 million in 1994 and aggregate approximately $23.4 million for the years 1995 through 1998.

Other Proceedings

In June 1991, the State of New Hampshire imposed a Nuclear Station Property Tax applicable only to the Seabrook Project. The Company paid its share of the tax, aggregating $[illegible].2 million through December 31, 1992. In October 1991 the Attorneys General of Connecticut, Massachusetts and Rhode Island petitioned the United States Supreme Court in an original jurisdiction case for a determination of the legality of the tax, and in January 1992 the Supreme Court agreed to take the case. The parties to the litigation and other Joint Owners of Seabrook entered into a Settlement Agreement on April 13, 1993. In general, the terms of the Settlement Agreement are expected to result in a significant reduction in annual state taxes paid by the Company. In addition, under the terms of the Settlement Agreement, certain of the prior payments of the tax by the Company will be permitted to be credited against future taxes due. The Bankruptcy Court has approved the Settlement Agreement with respect to the Company.

Note H — Subsequent Event

On November 23, 1994, the Company emerged from Bankruptcy and adopted a new basis of accounting as required by Statement of Position 90-7 "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" issued by the American Institute of Certified Public Accountants. Accordingly, the information contained in these financial statements is not comparable to the financial statements for periods beginning on or after November 23, 1994. The accompanying financial statements are not indicative of the financial position or the expected results of operations for periods beginning on or after November 23, 1994.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GREAT BAY POWER CORPORATION

March 22, 1996

By: JOHN A. TILLINGHAST

John A. Tillinghast
President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
JOHN A. TILLINGHAST John A. Tillinghast	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer and Principal Accounting Officer)	March 22, 1996
KENNETH A. BUCKFIRE Kenneth A. Buckfire	Director	March 22, 1996
WALTER GOODENOUGH Walter Goodenough	Director	March 22, 1996
ANDREW J. KURTZ Andrew J. Kurtz	Director	March 22, 1996
CHARLES A. LEEDS, JR. Charles A. Leeds, Jr.	Director	March 22, 1996

EXHIBIT INDEX

Exhibit No.	Description	Sequentially Numbered Page
2	First Modification to Bondholders' Committee's Fifth Amended Plan of Reorganization dated February 11, 1994 as amended by First Amendment to Modified Plan dated September 9, 1994.(2)	
3.1	Restated Articles of Incorporation of the Registrant as amended to date.(1)	
3.2	Amended and Restated By-laws of the Registrant adopted on November 23, 1994.(2)	
10.1	Agreement Between Bangor Hydro-Electric Company, Central Maine Power Company, Central Vermont Public Service Corporation, Fitchburg Gas and Electric Light Company, Maine Public Service Company and EUA Power Corporation relating to use of certain transmission facilities dated October 20, 1986.(2)	
10.2	Limited Guaranty by Eastern Utilities Associates of Decommissioning Costs in favor of Joint Owners of the Seabrook Project dated May 5, 1990.(2)	
10.3	Composite Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, as amended, dated November 1, 1990.(2)	
10.4	Seventh Amendment to and Restated Agreement for Seabrook Project Disbursing Agent as amended through and including the Second Amendment, by and among North Atlantic Energy Service Corporation, the Registrant and other Seabrook Project owners dated November 1, 1990.(2)	
10.5	Seabrook Project Managing Agent Operating Agreement by and among the North Atlantic Energy Service Corporation, the Registrant and parties to the Joint Ownership Agreement, dated June 29, 1992.(2)	
10.6	Settlement Agreement by and among EUA Power Corporation, Eastern Utilities Associates and the Official Bondholders' Committee dated November 18, 1992.(2)	
10.7	Marketing Agent Agreement between UNITIL Corporation and the Registrant dated April 1, 1993.(2)	
10.8	Purchased Power Agreement between UNITIL Power Corporation and the Registrant dated April 26, 1993.(2)	
10.9	Power Purchase Option Agreement between UNITIL Power Corporation and the Registrant dated April 26, 1993.(2)	
10.10	Second Mortgage and Security Agreement between UNITIL Power Corporation and the Registrant dated December 22, 1993.(2)	
10.11	Third Mortgage and Security Agreement between UNITIL Power Corporation and the Registrant dated December 22, 1993.(2)	
10.12	Registration Rights Agreement between the Registrant and the Selling Stockholders dated April 7, 1994 (the "Registration Rights Agreement").(2)	
10.13	Amendment to Registration Rights Agreement between the Registrant and the Selling Stockholders dated November 23, 1994.(2)	
10.14	Stock and Subscription Agreement among the Registrant and the Selling Stockholders dated April 7, 1994.(2)	
10.15	Acknowledgment and Amendment to Stock and Subscription Agreement, dated November 23, 1994.(2)	
10.16	Settlement Agreement by and among the Registrant, the Official Bondholders' Committee and the Selling Stockholders dated September 9, 1994.(2)	
10.17	Management and Administrative Services Agreement between UNITIL Resources, Inc. and the Registrant dated November 23, 1994.(2)	

Exhibit No.	Description	Sequentially Numbered Page
10.18	Employment Agreement between John A. Tillinghast and the Registrant dated November 23, 1994.(2)(7)	
10.19	Expense Sharing Agreement between Tillinghast Technology Interests, Inc. and the Registrant dated November 23, 1994.(2)	
10.20	Purchased Power Agreement between Freedom Electric Power Company and the Registrant dated March 2, 1995.(2)	
10.21	Letter Agreement, dated December 20, 1994, between the Registrant and the Selling Stockholders amending Registration Rights Agreement, as previously amended on November 23, 1994.(2)	
10.22	Letter Agreement, dated March 28, 1995, between the Registrant and the Selling Stockholders amending Registration Rights Agreement, as previously amended on November 23, 1994 and December 20, 1994.(2)	
10.23	Employment Agreement between John A. Tillinghast and the Registrant dated April 24, 1995.(3)(7)	
10.24	Incentive Stock Option Agreement, dated as of April 24, 1995, by and between John A. Tillinghast and the Registrant.(3)(7)	
10.25	New Expense Sharing Agreement between Tillinghast Technology Interest, Inc. and the Registrant dated April 24, 1995.(3)	
10.26	Employment Agreement between Frank W. Getman Jr. and the Registrant dated August 1, 1995.(4)(7)	
10.24	Incentive Stock Option Agreement, dated as of August 1, 1995, by and between Frank W. Getman Jr. and the Registrant.(4)(7)	
10.28	Services Agreement between PECO Energy Company and the Registrant dated November 3, 1995.(5)(6)	
10.29	Warrant Purchase Agreement between PECO Energy Company and the Registrant dated November 3, 1995.(5)	
10.30	Warrant, dated February 14, 1995, issued by the Registrant to PECO pursuant to the provisions of a Warrant Purchase Agreement.(1)	
10.31	Great Bay Power Corporation 1995 Stock Option Plan, as amended.(1)(7)	
16	Letter regarding Change in Certifying Accountant dated March 29, 1995.(2)	

(1) Filed as an exhibit to this Annual Report on Form 10-K.

(2) Filed as an exhibit to the Company's Registration Statement on Form S-1 (Registration No. 33-78232) declared effective on April 17, 1995 and incorporated herein by reference.

(3) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 1995 (File No. 0-25748) on May 9, 1995 and incorporated herein by reference.

(4) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1995 (File No. 0-25748) on August 14, 1995 and incorporated herein by reference.

(5) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1995 (File No. 0-25748) on November 14, 1995 and incorporated herein by reference.

(6) Confidential treatment granted as to certain portions.

(7) Management contract or compensation plan or arrangement required to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

BOARD OF DIRECTORS

John A. Tillinghast
Chairman of the Board
President

Kenneth A. Buckfire
Director,
Wasserstein Perella & Co.

Andrew J. Kurtz
Portfolio Manager,
Stonington Management Corporation

Charles A. Leeds, Jr.
Portfolio Manager,
Omega Advisors, Inc.

Walter H. Goodenough
Dallas, Texas

OFFICERS

John A. Tillinghast
Chairman of the Board
Chief Executive Officer
President
Treasurer

Frank W. Getman Jr.
Vice President
General Counsel
Secretary

CORPORATE COUNSEL

Hale and Dorr
60 State Street
Boston, Massachusetts 02109

TRANSFER AGENT

Boston EquiServe
P.O. Box 8200
Boston, Massachusetts 02266-8200

INDEPENDENT AUDITORS

Arthur Andersen LLP
One International Place
Boston, Massachusetts 02110-2604

CORPORATE OFFICES

20 Ladd Street
Portsmouth, New Hampshire 03801-4080

ANNUAL MEETING

The Annual Meeting of Stockholders will be held on April 16, 1996 at 10:00 a.m. EST at the Grand Hyatt New York, Palace Room, Park Avenue at Grand Central, New York, New York.

FORM 10-K

For a copy of the Form 10-K Annual Report filed with the Securities and Exchange Commission, write to the Company's Corporate Offices or call (603) 433-8822.

STOCK INFORMATION

The Company's stock is listed on the Nasdaq National Market under the symbol 'GBPW'.

FORM 10-K

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549-1004

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]

For the fiscal year ended **December 31, 1995**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

For the transition period from ________ to ________

Commission File Number	Registrant; State of Incorporation, Address; and Telephone Number	I.R.S Employer Identification No.
1-5324	**NORTHEAST UTILITIES** (a Massachusetts voluntary assocation) **174 Brush Hill Avenue** **West Springfield, Massachusetts 01090-0010** Telephone: **(413) 785-5871**	**04-2147929**
0-11419	**THE CONNECTICUT LIGHT AND POWER COMPANY** (a Connecticut corporation) **Selden Street** **Berlin, Connecticut 06037-1616** Telephone: **(860) 665-5000**	**06-0303850**
1-6392	**PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE** (a New Hampshire corporation) **1000 Elm Street** **Manchester, New Hampshire 03105-0330** Telephone: **(603) 669-4000**	**02-0181050**
0-7624	**WESTERN MASSACHUSETTS ELECTRIC COMPANY** (a Massachusetts corporation) **174 Brush Hill Avenue** **West Springfield, Massachusetts 01090-0010** Telephone: **(413) 785-5871**	**04-1961130**
33-43508	**NORTH ATLANTIC ENERGY CORPORATION** (a New Hampshire corporation) **1000 Elm Street** **Manchester, New Hampshire 03105-0330** Telephone: **(603) 669-4000**	**06-1339460**

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
Northeast Utilities	Common Shares, $5.00 par value	New York Stock Exchange, Inc.
The Connecticut Light and Power Company	9.3% Cumulative Monthly Income Preferred Securities Series A (1)	New York Stock Exchange, Inc.

(1) Issued by CL&P Capital, L.P., a wholly owned subsidiary of The Connecticut Light and Power Company ("CL&P"), and guaranteed by CL&P.

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Northeast Utilities	Common Share Warrants, no par value, exercisable at $24 per share
The Connecticut Light and Power Company	Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are outstanding:

$1.90	Series	of 1947	4.96%	Series	of 1958
$2.00	Series	of 1947	4.50%	Series	of 1963
$2.04	Series	of 1949	5.28%	Series	of 1967
$2.20	Series	of 1949	6.56%	Series	of 1968
3.90%	Series	of 1949	$3.24	Series G	of 1968
$2.06	Series E	of 1954	7.23%	Series	of 1992
$2.09	Series F	of 1955	5.30%	Series	of 1993
4.50%	Series	of 1956			

Public Service Company of New Hampshire — Preferred Stock, par value $25.00 per share, issuable in series, of which the following series are outstanding:

10.60% Series A of 1991

Western Massachusetts Electric Company — Preferred Stock, par value $100.00 per share, issuable in series, of which the following series is outstanding:

7.72% Series B of 1971

Class A Preferred Stock, par value $25.00 per share, issuable in series, of which the following series are outstanding:

7.60% Series of 1987

Dutch Auction Rate Transferable Securities, 1988 Series

NORTHEAST UTILITIES
THE CONNECTICUT LIGHT AND POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
WESTERN MASSACHUSETTS ELECTRIC COMPANY
NORTH ATLANTIC ENERGY CORPORATION

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PART I

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes X **No ___**

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of **Northeast Utilities'** Common Share, $5.00 Par Value, held by nonaffiliates, was **$2,966,776,865**, based on a closing sales price of **$23 1/4** per share for the **127,603,306** common shares outstanding on February 29, 1996. **Northeast Utilities** holds all of the **12,222,930** shares, **1,000** shares, **1,072,471** shares and **1,000** shares of the outstanding common stock of **The Connecticut Light and Power Company, Public Service Company of New Hampshire, Western Massachusetts Electric Company,** and **North Atlantic Energy Corporation,** respectively.

Documents Incorporated by Reference:

Description	Part of Form 10-K into Which Document is Incorporated
Portions of Annual Reports to Shareholders of the following companies for the year ended December 31, 1995:	
Northeast Utilities	Part II
The Connecticut Light and Power Company	Part II
Public Service Company of New Hampshire	Part II
Western Massachusetts Electric Company	Part II
North Atlantic Energy Corporation	Part II
Portions of the Northeast Utilities Proxy Statement dated April 1, 1996.	Part III

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NORTHEAST UTILITIES
THE CONNECTICUT LIGHT AND POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
WESTERN MASSACHUSETTS ELECTRIC COMPANY
NORTH ATLANTIC ENERGY CORPORATION

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PART II

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PART IV

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report:

COMPANIES

NU	Northeast Utilities
CL&P	The Connecticut Light and Power ompany
Charter Oak	Charter Oak Energy, Inc.
WMECO	Western Massachusetts Electric Company
HWP	Holyoke Water Power Company
NUSCO or the Service Company	Northeast Utilities Service Company
NNECO	Northeast Nuclear Energy Company
NAEC	North Atlantic Energy Corporation
NAESCO or North Atlantic	North Atlantic Energy Service Corporation
PSNH	Public Service Company of New Hampshire
RRR	The Rocky River Realty Company
HEC	HEC Inc.
Quinnehtuk	The Quinnehtuk Company
the System	The Northeast Utilities System
CYAPC	Connecticut Yankee Atomic Power Company
MYAPC	Maine Yankee Atomic Power Company
VYNPC	Vermont Yankee Nuclear Power Corporation
YAEC	Yankee Atomic Electric Company
the Yankee Companies	CYAPC, MYAPC, VYNPC, and YAEC

GENERATING UNITS

Millstone 1	Millstone Unit No. 1, a 660-MW nuclear generating unit completed in 1970
Millstone 2	Millstone Unit No. 2, an 870-MW nuclear electric generating unit completed in 1975
Millstone 3	Millstone Unit No. 3, a 1,154-MW nuclear electric generating unit completed in 1986
Seabrook or Seabrook 1	Seabrook Unit No. 1, a 1,148-MW nuclear electric generating unit completed in 1986. Seabrook 1 went into service in 1990.

REGULATORS

DOE	U.S. Department of Energy
DPU	Massachusetts Department of Public Utilities
DPUC	Connecticut Department of Public Utility Control
MDEP	Massachusetts Department of Environmental Protection
CDEP	Connecticut Department of Environmental Protection
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
NHDES	New Hampshire Department of Environmental Services
NHPUC	New Hampshire Public Utilities Commission

GLOSSARY OF TERMS

REGULATORS (Continued)

NRC	Nuclear Regulatory Commission
SEC	Securities and Exchange Commission

Other

1935 Act	Public Utility Holding Company Act of 1935
CAAA	Clean Air Act Amendments of 1990
DSM	Demand-Side Management
Energy Policy Act	Energy Policy Act of 1992
EWG	Exempt wholesale generator
FAC	Fuel adjustment clause
FPPAC	Fuel and purchased power adjustment clause (PSNH)
FUCO	Foreign utility company
GUAC	Generation utilization adjustment clause (CL&P)
IRM	Integrated resource management
kWh	Kilowatt-hour
MW	Megawatt
NBFT	Niantic Bay Fuel Trust, lessor of nuclear fuel used by CL&P and WMECO
NEPOOL	New England Power Pool
NUGs	Nonutility generators
NUG&T	Northeast Utilities Generation and Transmission Agreement
QF	Qualifying facility

NORTHEAST UTILITIES
THE CONNECTICUT LIGHT AND POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
WESTERN MASSACHUSETTS ELECTRIC COMPANY
NORTH ATLANTIC ENERGY CORPORATION

PART I

ITEM 1. BUSINESS

THE NORTHEAST UTILITIES SYSTEM

Northeast Utilities (NU) is the parent company of the Northeast Utilities system (the System). NU is not an operating company. The System furnishes retail electric service in Connecticut, New Hampshire and western Massachusetts through four of NU's wholly owned subsidiaries (The Connecticut Light and Power Company [CL&P], Public Service Company of New Hampshire [PSNH], Western Massachusetts Electric Company [WMECO] and Holyoke Water Power Company [HWP]). In addition to their retail electric service, CL&P, PSNH, WMECO and HWP (including its wholly owned subsidiary, Holyoke Power and Electric Company [HPE]) (the System companies) together furnish firm wholesale electric service to five municipal electric systems and one investor-owned utility. The System companies also supply other wholesale electric services to various municipalities and other utilities. The System serves about 30 percent of New England's electric needs and is one of the 20 largest electric utility systems in the country as measured by revenues.

North Atlantic Energy Corporation (NAEC) is a special-purpose subsidiary of NU that owns a 35.98 percent interest in the Seabrook nuclear generating facility (Seabrook) in Seabrook, New Hampshire and sells its share of the capacity and output from Seabrook to PSNH under two life-of-unit, full-cost recovery contracts.

Several wholly owned subsidiaries of NU provide support services for the System companies and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, information resources, engineering, financial, legal, operational, planning, purchasing and other services to the System companies. North Atlantic Energy Service Corporation (NAESCO) has operational responsibility for Seabrook. Northeast Nuclear Energy Company (NNECO) acts as agent for the System companies and other New England utilities in operating the Millstone nuclear generating facilities in Connecticut. Three other subsidiaries construct, acquire or lease some of the property and facilities used by the System companies.

NU has two other principal subsidiaries, Charter Oak Energy, Inc. (Charter Oak) and HEC Inc. (HEC), which have nonutility businesses. Directly and through subsidiaries, Charter Oak develops and invests in cogeneration, small-power production and other forms of nonutility generation and in exempt wholesale generators (EWGs)(collectively, NUGs) and foreign utility companies (FUCOs) as permitted under the Energy Policy Act of 1992 (Energy Policy Act). HEC provides energy management services for the System's commercial, industrial and institutional electric customers and others. See "Nonutility Businesses."

NU is functionally organized into two core business groups. The first group, the Energy Resources Group, is devoted to energy resource acquisition, nuclear, fossil and hydroelectric generation and wholesale marketing. The second group, the Retail Business Group, oversees all customer service, transmission and distribution operations and retail marketing in Connecticut, New Hampshire and Massachusetts. These two core business groups receive services from various support functions known collectively as the Corporate Center.

PUBLIC UTILITY REGULATION

The System is regulated by various federal and state agencies.

NU is regulated as a registered electric utility holding company under the Public Utility Holding Company Act of 1935 (1935 Act). Accordingly, the Securities and Exchange Commission (SEC) has jurisdiction over NU and its subsidiaries with respect to, among other things, securities issues, sales and acquisitions of securities and utility assets, intercompany loans, services performed by and for associated companies, certain accounts and records, involvement in nonutility operations and dividends. The 1935 Act limits the System, with certain exceptions, to the business of being an electric utility in the Northeastern region of the country. In 1995, the staff of the SEC recommended "conditional repeal" of the 1935 Act and substantial loosening of rules presently restricting NU's capital-raising and diversification activities. In 1995, a bill was introduced in the United States Senate to repeal the 1935 Act. To date these proposals have not been acted on.

The System companies are also subject to the Federal Power Act as administered by the Federal Energy Regulatory Commission (FERC). FERC regulates the wholesale power sales and interstate transmission service of the System. The Energy Policy Act amended the Federal Power Act to authorize FERC to order wholesale transmission wheeling services and under certain circumstances to require electric utilities to enlarge transmission capacity necessary to provide such services. FERC's authority to order wheeling does not extend to retail wheeling, and FERC may not issue a wheeling order that is inconsistent with state laws governing the retail marketing areas of electric utilities. For more information regarding retail wheeling, see "Competition and Marketing-Retail Marketing" and "Rates."

The Nuclear Regulatory Commission (NRC) has broad jurisdiction over the System's nuclear units. Each of the System companies is subject to broad regulation by its respective state and/or local regulatory authorities with jurisdiction over the service areas in which each company operates. For more information regarding recent NRC actions taken with respect to the System's nuclear units, including the recent designation of Millstone Station on the NRC's watch list, see "Electric Operations-Nuclear Generation-Nuclear Plant Performance."

The System incurs substantial capital expenditures and operating expenses to identify and comply with environmental, energy, licensing and other regulatory requirements, including those described herein, and it expects to incur additional costs to satisfy further requirements in these and other areas of regulation. For more information regarding specific regulatory actions and proceedings, see generally "Rates," "Electric Operations" and "Regulatory and Environmental Matters."

COMPETITION AND MARKETING

COMPETITION AND COST RECOVERY

Competition in the energy industry continues to grow as a result of legislative and regulatory action, surplus generating capacity, technological advances, relatively high prices in certain regions of the country, including New England, and the increased availability of natural gas.

A major risk of competition for many utilities, including the System, is "strandable costs." These are costs that have been incurred by utilities in the past to meet their public service obligations, with the expectation that they would be recovered from customers in the future, and yet under certain circumstances might not be recoverable from customers in a fully competitive electric utility industry. The System's exposure to the risk of strandable costs is primarily based on: (i) the System's relatively high investment in nuclear generating capacity, which has a high initial cost to build; (ii) state-mandated purchased-power arrangements priced above market and (iii) significant regulatory assets, which are those costs (including purchased-power costs) that have been deferred by state regulators for future collection from customers.

As of December 31, 1995, the System's regulatory assets totaled approximately $2 billion. The System expects to recover substantially all of its regulatory assets from customers, and unless amortization is changed from currently scheduled rates, the System's regulatory assets are expected to be substantially decreased in the next five years. There are many contingencies, however, that may affect the System's ability to recover strandable costs, including the results of various electric utility restructuring initiatives in the System's service territory and the uncertainty of future rate schedules for CL&P, WMECO and PSNH.

In 1995, regulators in both Connecticut and Massachusetts concluded that electric utilities should be allowed a reasonable opportunity to recover strandable costs. There has been no such finding in New Hampshire; however, on February 22, 1996, PSNH and the staff of the New Hampshire Public Utilities Commission (NHPUC) reached an agreement, subject to further approvals, on a limited, retail wheeling program under which PSNH would recover all of its strandable costs allocable to this program.

The System believes that its assets would be worth more than their net depreciated value if all segments of the industry, not only generation, were to be deregulated and become competitive. These assets could include the transmission and distribution system and much of the System's coal-fired and hydroelectric generation.

The worst case scenario for the System would be for a rapid movement to an openly competitive market on terms such that all of its strandable costs cannot be recovered with little opportunity to realize the true value of below-market assets if such assets remain subject to traditional regulation. The System cannot predict at this time what will be the ultimate result of the various legislative and regulatory restructuring initiatives.

Competitive forces in the utility industry also create a risk that customers may choose alternative energy suppliers or relocate outside of the System's service territory. In response, the System has developed, and is continuing to develop, a number of marketing initiatives to retain and continue to serve its existing customers. In late 1994 the System began a reengineering process, which is ongoing, to become more competitive while improving customer service and maintaining a high level of operational performance.

The System's strandable cost risk and exposure to revenue loss from competitive forces are somewhat mitigated by a diverse customer retail base and lack of significant dependence on any one retail customer or industry.

RETAIL MARKETING

The System companies continue to operate predominantly in state-approved franchise territories under traditional cost-of-service regulation. Retail wheeling, under which a retail customer would be permitted to select an electricity supplier other than its local electric utility and require the local electric utility to transmit the power to the customer's site, is not generally required in any of the System's jurisdictions. Emphasis on developing approaches to deregulation, however, is growing nationwide. For additional information regarding retail wheeling and electric industry restructuring initiatives in the System's service territory, see "Rates."

While retail wheeling is not yet generally required in the System's retail service territory, competitive forces nonetheless are influencing retail pricing. The System companies have been devoting increasing attention in recent years to negotiating long-term power supply arrangements with certain retail customers. Such arrangements are offered to customers who require an incentive to locate or expand their operations in the System's service territory, are considering leaving or reducing operations in the service territory, are facing short-term financial problems or are considering generating their own electricity.

Approximately 6 percent of the System's retail revenues were under negotiated rate agreements at the end of 1995, up from 4 percent at the end of 1994. In 1995, those negotiated rate reductions amounted to approximately $35 million, up from $20 million in 1994. CL&P accounted for approximately $19 million of the 1995 rate reductions, PSNH for $7.5 million, WMECO for $7 million and HWP for $1.5 million. Management believes that the level of contractual rate reductions is likely to increase further in 1996, but that these agreements provide long-term benefits to the System by helping to stabilize retail revenues and attract additional retail load to its service territory. Currently, the costs of providing these discounts are borne by NU shareholders through reduced earnings prior to rate changes in the System's various jurisdictions. The System companies may request that such costs be shared by their customers during subsequent rate proceedings.

Regulators in both Connecticut and New Hampshire took steps in 1995 that allowed electric utilities additional flexibility in negotiating special rate agreements with electric customers. In March 1995, the Connecticut Department of Public Utility Control (DPUC) approved new guidelines for CL&P's general rate riders that (i) allow CL&P to enter into special rate agreements of up to ten years with eligible customers, (ii) expand the eligibility for such rate agreements, (iii) authorize CL&P to provide additional services instead of rate concessions and (iv) lower the minimum pricing for such rate agreements. The Connecticut Consumer Counsel (CCC) appealed the DPUC's decision to the Connecticut Superior Court in May 1995, and the matter is pending. Previously, agreements with existing customers that were longer than five years had to be individually approved by the DPUC. CL&P's ten-year agreement with Pratt & Whitney, CL&P's largest industrial customer, was approved by the DPUC in June 1995 under the DPUC's previous rules.

In November 1995, the NHPUC issued guidelines permitting electric utilities to offer economic development and business retention rates. On February 23, 1996, the NHPUC issued an order accepting a package of rates submitted by PSNH that would result in rate reductions of up to 20 percent for existing manufacturers, who may close their business or move out of the state, and up to 30 percent for manufacturers creating new or expanded electric load. The order, however, includes a condition that prevents PSNH from recovering from other customers the difference between the economic development rates and full tariff rates, which would have the effect of PSNH losing money on each sale. As a result, PSNH will seek reconsideration by the NHPUC before deciding whether to offer an economic development rate. The order does not include the same restriction for business retention rates, and therefore, PSNH will proceed with the necessary tariff filings to offer these rates.

In 1994, the Massachusetts Department of Public Utilities (DPU) authorized WMECO to reduce rates by 5 percent for all customers whose demand exceeds one megawatt (MW) as long as those customers agree to give WMECO at least five years notice before generating their own power or purchasing it from an alternative supplier. The DPU also permits WMECO to offer specified discounts with a five-year term to attract new businesses and encourage business expansion in the state. The DPU must approve all other special rate agreements individually.

Demand-side management (DSM) programs are also used by the System to make its customers more efficient and viable employers in its service territory. The System companies expect to spend approximately $50 million in 1996 on DSM programs. These programs help customers improve the efficiency of their electric lighting, manufacturing and heating, ventilating and air conditioning systems. DSM program costs are recovered from customers through various cost recovery mechanisms. For further information on the System's DSM programs, see "Rates."

The System is continuing to expand its Retail Marketing organization to provide better customer service. Beginning in 1996, the System expects to devote significantly more resources to its retail marketing efforts. Much of the increased spending will be for developing new energy-related products and services and investing in technology that will be used to support new initiatives.

WHOLESALE MARKETING

The System acts as both a buyer and a seller of electricity in the highly competitive wholesale electricity market in the Northeastern United States (Northeast). Because economic growth in this region has been modest since 1989 and because many new sources of power have become operational since that time, a significant surplus of generating capacity currently exists in New England and New York. As a result, wholesale electricity pricing is now significantly lower than it was in the late 1980s.

As a result of the continued expiration of some older, higher priced contracts, the System's wholesale revenues decreased to $303 million in 1995 from $331 million in 1994. Over the same period, sales of energy declined from 9.12 billion kilowatt-hours (KWh) in 1994 to 8.72 billion KWh in 1995. As a result of new contracts entered into in recent years, wholesale revenues in 1996 are expected to be comparable in amount to 1995.

The System's most important wholesale market at this time remains New England. Of the $303 million in total 1995 wholesale revenues, approximately $280 million came from sales to investor-owned, cooperative and municipal utilities in New England. Because most investor-owned utilities in New England have surplus generation, sales to those utilities have declined in recent years while sales to municipal utilities have increased. In 1995, revenues from sales to one new municipal customer, Madison Electric Works in Madison, Maine, were approximately $7 million. That load is expected to grow in the coming years as a paper company in Madison expands its operations.

The largest cooperative served by the System is the Connecticut Municipal Electric Energy Cooperative (CMEEC), which accounted for $71 million of wholesale revenues in 1995. Half of those sales resulted from a new ten-year agreement signed in January 1995 under which CMEEC buys power from CL&P on behalf of the Town of Wallingford, Connecticut. The contract price includes amortization of a lump sum payment to CL&P for early termination of a prior agreement with Wallingford directly for a comparable amount of System power sales.

In 1995, the System also had sales of $52 million to the New Hampshire Electric Cooperative (NHEC), approximately 90 percent of PSNH's wholesale revenues. NHEC is a party to a full-requirements power supply agreement with PSNH that cannot be terminated by its terms prior to November 1, 2006. In 1995, PSNH filed a complaint against NHEC with FERC challenging NHEC's decision to take bids on 20 megawatts (MW) of power, representing 14 percent of NHEC's total load, from qualifying facilities (QFs) to replace a comparable amount of capacity from PSNH supplied under the power supply agreement. PSNH believes that the solicitation of such bids violated the terms of its power supply agreement. That complaint is still pending at FERC and NHEC has not yet accepted any bids from new suppliers.

The System's second-largest wholesale market is New York State. In 1995, the System's sales to utilities in New York accounted for $14 million of revenues. Also in 1995, the Suffolk County Electric Agency announced that the System had won 200 MW of a 300-MW bid to provide base-load generation to customers in Suffolk County, Long Island. This contract, however, is subject to FERC approval and could be contested by other parties. Accordingly, it is unclear whether or when that contract will take effect.

The System also plans to expand its wholesale market through electric brokering activities and wholesale sales at market-based rates. On August 18, 1995, CL&P, PSNH, WMECO, NAEC and NUSCO received an order from the SEC under the 1935 Act allowing them to engage in electric brokering and marketing activities primarily throughout New England, New York, Pennsylvania, New Jersey and Maryland with both interconnected and remote parties. This order will allow the companies to arrange to both broker or buy and sell electricity from owned and contracted sources outside the

System's retail service area. To date, the System has not received approval from FERC permitting it to sell power outside of New England at market-based rates.

The System's transmission system is an open-access wholesale transmission system: other parties, either utilities or independent power producers, can use NU's transmission system to move power from a seller to a wholesale buyer at FERC-approved rates, provided adequate capacity across those lines is available and service reliability is not endangered. See "Electric Operations—Transmission Access" for further information on pending FERC proceedings relating to the System's transmission tariffs.

RATES

CONNECTICUT RETAIL RATES

GENERAL

CL&P's retail rates are subject to the jurisdiction of the DPUC. Connecticut law provides that revised rates may not be put into effect without the prior approval of the DPUC. Connecticut law also authorizes the DPUC to order a rate reduction under certain circumstances before holding a full-scale rate proceeding. The DPUC is further required to review a utility's rates every four years if there has not been a rate proceeding during such period.

The DPUC issued a decision in CL&P's most recent rate case in June 1993 (1993 Decision) approving a multi-year rate plan that provided for annual retail rate increases of $46.0 million, or 2.01 percent, in July 1993, $47.1 million, or 2.04 percent, in July 1994 and $48.2 million, or 2.06 percent, in July 1995. These rate increases were implemented as scheduled. CL&P's rates in place as of July 1995 will remain in effect after July 1, 1996 unless a rate change is approved by the DPUC. For more information regarding the 1993 Decision, see "Item 3. Legal Proceedings."

ELECTRIC INDUSTRY RESTRUCTURING IN CONNECTICUT

Throughout the first half of 1995, the DPUC conducted a generic proceeding studying the restructuring of the electric industry and competition in order to develop findings and recommendations to be presented to legislative policymakers. In March 1995, as part of this proceeding, CL&P introduced its plan, entitled "Path to a Competitive Future," for the future of the electric industry and related regulation in Connecticut. The plan calls for full recovery of all existing plant and regulatory assets and a fully competitive market for electricity by approximately 2003.

On July 14, 1995, the DPUC issued its final decision in this proceeding. The decision stressed the importance of retaining the benefits of the existing electric system, which it described as the "least costly and most reliable in the world." One key conclusion was that retail access could result in benefits to customers under certain circumstances, but addressing the many transition issues must precede such access. In addition, the decision concluded that utilities are entitled to a reasonable opportunity to recover costs potentially strandable by the evolution toward competitive markets. The decision did not specify any particular time-frame for competition.

In February 1996, the Connecticut Legislative Task Force for restructuring the electric industry issued its interim report to the legislature. The report broadly establishes certain restructuring goals, including lowering electric prices (possibly through, among other things, a reduction in the gross earnings tax on electric revenues) and assuring reliable electric service to all customers. A final report to the legislature is due by January 1, 1997.

CL&P ADJUSTMENT CLAUSES

CL&P has a fossil fuel adjustment clause (FAC) which adjusts retail rates for changes in the price of fossil fuel reflected in base rates. If the price of fossil fuel increases above the level reflected in base rates, CL&P can recover the amount of the increase from retail customers on a current basis, subject to periodic review by the DPUC. Conversely, if the price of fossil fuel decreases below the level reflected in base rates, CL&P must credit the amount of the decrease on a current basis to its customers through the FAC. The FAC also adjusts retail rates for the costs of power purchased from third parties, including NUGs. On December 28, 1995, the DPUC approved, in significant part, CL&P's request to exclude from the calculation of the FAC rate both the fuel costs and the KWh sales of CL&P's firm and non-firm wholesale sales, thus neutralizing the effect of these sales on the fuel clause and eliminating a critical disincentive to making such sales.

CL&P's current retail rates also assume that the nuclear units in which CL&P has entitlements will operate at a 72 percent composite capacity factor. A generation utilization adjustment clause (GUAC) levels the effect on rates of fuel costs incurred or avoided due to variations in nuclear generation above and below that performance level. Because nuclear fuel is less expensive than any other fuel utilized by the System, when actual nuclear performance is above the specified level, net fuel costs are lower than the costs reflected in base rates and when nuclear performance is below the specified level, net fuel costs are higher than the costs reflected in base rates. At the end of each 12-month period ending July 31, these net variations from the costs reflected in base rates are, with DPUC approval, generally refunded to or collected from customers over the subsequent 12-month period beginning September 1.

For the 1992-1993 and 1993-1994 GUAC periods, the DPUC issued decisions that disallowed $7.9 million and $7.8 million, respectively, of the GUAC deferrals accrued during these periods, finding that CL&P had overrecovered those amounts through base rate fuel recoveries. CL&P appealed both of these decisions and prevailed in the Connecticut Superior Court. The DPUC and other parties then appealed that court's decisions to the Connecticut Supreme Court. Oral argument before the Supreme Court will be held in the Spring of 1996.

On January 17, 1995, the DPUC issued a decision that allowed CL&P to continue to recover $80 million of the GUAC costs for the 1994-95 GUAC period (net of $19 million of asserted base fuel overrecoveries for the period) over an 18-month period (instead of the usual 12 months) beginning in September 1995. CL&P has appealed the $19 million that was set aside from its allowed recovery and will seek to join its appeal on this decision to the appeals currently pending before the Connecticut Supreme Court. The DPUC's decision on the 1994-1995 GUAC period is also subject to the results of prudence reviews of the extended 1994-1995 outage at Millstone 2 and another 1994 Millstone 2 outage discussed below. For additional information regarding recent nuclear outages, see "Electric Operations-Nuclear Generation-Nuclear Plant Performance."

In August 1995, the DPUC began investigating the adoption of a fuel clause designed to track and recover all costs of energy incurred to serve customers, which would supersede the current FAC and GUAC. A final decision is scheduled for April 1996.

The DPUC has conducted several reviews to examine the prudence of certain costs, including purchased-power costs, incurred in connection with outages at various nuclear units located in Connecticut, that occurred during the period July 1991 to February 1992. Three of these prudence reviews are still pending at the DPUC. Approximately $92 million of costs are at issue in these remaining cases. Management believes its actions with respect to these outages have been prudent and does not expect the outcome of the appeals to result in material disallowances.

On April 10, 1995, the DPUC initiated a proceeding to investigate the prudence of an extended outage at Millstone 2, which ended on June 18, 1994, involving the repair of damage to a reactor coolant pump. Approximately $13 million of replacement power costs related to the outage are at issue in this proceeding. Hearings in this proceeding are expected to begin in March 1996.

DEMAND-SIDE MANAGEMENT

CL&P participates in a collaborative process for the development and implementation of DSM programs for its residential, commercial and industrial customers. CL&P is allowed to recover DSM costs in excess of costs reflected in base rates over periods ranging from approximately four to ten years.

On April 12, 1995, the DPUC issued an order approving CL&P's budget of $36.7 million for 1995 DSM expenditures and an amortization period for new expenditures of approximately four years. On October 3, 1995, CL&P filed its 1996-1997 DSM programs and budgets with the DPUC. CL&P proposed a budget level of $37.1 million for 1996 DSM expenditures and an amortization period for new expenditures of approximately 2.4 years. CL&P's unrecovered DSM costs at December 31, 1995, excluding carrying costs, which are collected currently, were approximately $117 million.

NEW HAMPSHIRE RETAIL RATES

GENERAL

PSNH's 1989 Rate Agreement (Rate Agreement) with the state of New Hampshire provides for seven base rate increases of 5.5 percent per year beginning in 1990 and a comprehensive fuel and purchased power adjustment clause (FPPAC). The first six base rate increases went into effect as scheduled and the remaining base rate increase is scheduled to be put into effect on June 1, 1996, concurrently with the semiannual adjustment for the FPPAC. Political and economic pressures, caused by PSNH's high retail electric rates, may force PSNH to accept less than an additional 5.5 percent rate increase scheduled for 1996, including an FPPAC increase; may lead to challenges to the Rate Agreement in the future; and may make recoveries of deferred costs after June 1, 1997 more difficult. The Rate

Agreement provides that PSNH's rates will be subject to traditional rate regulation after the fixed rate period expires on June 1, 1997, but that the FFPAC will continue through June 1, 2000. The base rates effective as of June 1, 1996 will remain in effect after June 1, 1997 unless a rate change is approved by the NHPUC. For additional information regarding a recent lawsuit concerning the Rate Agreement, see "Item 3. Legal Proceedings."

ELECTRIC INDUSTRY RESTRUCTURING IN NEW HAMPSHIRE

On February 22, 1996, PSNH and the staff of the NHPUC reached an agreement that, if approved by the NHPUC, would resolve the terms of PSNH's participation in an Electric Retail Competition Pilot Program (Program) in New Hampshire. Under this agreement, PSNH will provide access to approximately 3 percent of its retail customers (35.13 MW) to other electric suppliers. PSNH will charge participating customers for delivery services, comprised of distribution, transmission, acquisition premium and access charge components. PSNH would recover all strandable costs through these charges. Only the energy portion of its tariffs, which account for approximately 20 percent of PSNH's typical retail bill, would be exposed to alternative suppliers. Program participants will also receive a 10 percent "incentive rebate" off PSNH's traditional rates to encourage participation in the Program. The System estimates that, due to the 10 percent incentive feature, the Program, if implemented as proposed, could cost PSNH approximately $5 million over its two-year term.

The settlement terms are not binding on any future restructuring programs. The System companies also need FERC approval to allow Program participants access to the System's transmission system. Although the Program is scheduled to begin on May 28, 1996, this date is subject to both state and federal regulatory approvals.

If the above-settlement is not approved by the NHPUC, PSNH could be subject to the final guidelines for the Program issued by the NHPUC on February 28, 1996. The guidelines propose a two-year retail wheeling experiment under which a selected group of retail customers aggregating 50 MW of demand would be free to purchase power from suppliers other than their franchised local utility. Strandable costs resulting from the Program would be split equally between utility investors and participating customers, but, if requested, the NHPUC would allow for a review of these costs after the conclusion of a separate strandable cost proceeding.

On January 9, 1996, legislation was introduced in New Hampshire, requiring electric utilities to submit restructuring plans to the NHPUC by June 30, 1996, with final approval by June 30, 1997. The NHPUC would be further directed to implement full retail competition by June 30, 1998 or at the earliest date determined to be in the public interest by the NHPUC.

Under the New Hampshire's Limited Electrical Energy Producers Act (LEEPA), a qualifying generator of not greater than 5-MW capacity is permitted to sell its output to up to three retail customers. LEEPA also provides that the local franchised utility could be ordered to wheel the energy to these retail customers. On January 8, 1996, the NHPUC issued an order stating that the LEEPA retail wheeling provision was not pre-empted by federal law and that it had authority to order such retail wheeling service if it was found to be in the public good.

In 1994, Freedom Electric Power Company, now known as Freedom Energy Company, LLC (Freedom), filed a petition with the NHPUC for permission to operate as a retail electric utility selling to large industrial customers in New Hampshire, including customers of PSNH. On June 6, 1995, the NHPUC determined that electric utility franchises in New Hampshire are not exclusive as a matter of law. PSNH appealed this decision to the New Hampshire Supreme Court. Oral arguments on the appeal were heard on February 8, 1996. Pending this appeal and the related FERC proceeding referenced below, the NHPUC has delayed further activity in the underlying proceeding, including whether to allow Freedom to operate as a retail electric utility.

On July 14, 1995, Freedom filed a petition for declaratory ruling with FERC requesting a ruling that it is entitled to transmission access from PSNH. PSNH and numerous parties seeking intervenor status in this proceeding have filed comments with FERC opposing Freedom's petition as a sham transaction prohibited by the Energy Policy Act.

FPPAC

The FPPAC provides for the recovery or refund by PSNH, for the ten-year period beginning on May 16, 1991, of the difference between its actual prudent energy and purchased power costs and the estimated amounts of such costs included in base rates established by the Rate Agreement. The FPPAC amount is calculated for a six-month period based on forecasted data and is reconciled to actual data in subsequent FPPAC billing periods.

For the period December 1, 1994 through November 30, 1995, the NHPUC approved a continuation of the FPPAC rate that had been in effect during the last half of 1994. This rate treatment allowed PSNH to limit overall rate increases in 1995 to a level that did not exceed an overall 5.5 percent increase, while maintaining an FPPAC rate level sufficient to collect 1994 Seabrook refueling costs. On November 27, 1995, the NHPUC approved a zero rate for the FPPAC period December 1, 1995 through May 31, 1996 that resulted in a 2.6 percent decrease in rates.

On April 4, 1995, the NHPUC opened a proceeding to consider whether under the Rate Agreement PSNH may recover its $28 million of expenditures-including approximately $22 million for pollution control additions at the Merrimack fossil generating station-and approximately $3.5 million of annual operating and maintenance expenses necessary for current compliance with the Clean Air Act Amendments of 1990 (CAAA) at PSNH's fossil generating stations. Also at issue is the prudence of PSNH's use of the selective catalytic reduction technology at Merrimack Station's Unit 2. Since June 1, 1995, the NHPUC has allowed PSNH to collect its CAAA costs through FPPAC until there is a final decision in this proceeding. For more information regarding the CAAA, see "Regulatory and Environmental Matters-Environmental Regulation-Air Quality Requirements."

NUGs

The costs associated with purchases by PSNH from certain NUGs at prices above the level assumed in rates are deferred and recovered through the FPPAC over ten years. As of December 31, 1995, NUG deferrals, including the remaining buy-out of two wood-fired NUGs discussed below, totaled approximately $192 million.

Under the Rate Agreement, PSNH and the State of New Hampshire have an obligation to use their best efforts to renegotiate burdensome purchased power arrangements with 13 specified NUGs that were selling their output to PSNH under long-term rate orders. If authorized, PSNH will exchange near-term cash payments for partial relief from high-cost purchased power obligations to the NUGs, with such payments and an associated return on the unamortized portion being recoverable from customers in a future amortization period.

In 1994, the NHPUC approved new purchased power agreements with five hydroelectric NUGs, which management anticipates will result in a decrease in payments to these NUGs during a year with normal waterflow of approximately 14 percent, or $1.4 million per year. The first of these new power purchase agreements will expire in 2022.

In addition, PSNH has been involved in negotiations with eight wood-fired NUGs. In September 1994, the NHPUC approved settlement agreements with two of these wood-fired NUGs covering approximately 20 MW of capacity. Pursuant to the settlement agreements, PSNH paid the owners approximately $40 million in exchange for the cancellation of the rate orders under which these NUGs sold their entire output at rates in excess of PSNH's replacement power costs. As of December 31, 1995, PSNH had not yet recovered the approximately $34.2 million of deferred costs remaining to be collected on these settlement agreements. These NUGs also agreed not to compete with PSNH or other System subsidiaries in New Hampshire.

PSNH has reached agreements, subject to NHPUC approval, with the six remaining NUGs. The NHPUC will conduct hearings on four of the final settlement agreements during the first half of 1996, while the parties finalize the terms of the two remaining agreements. The six agreements could result in net savings of approximately $430 million to PSNH's customers over a period of 20 years following guaranteed payments of approximately $250 million. If the NHPUC fails to provide for full recovery of strandable costs, however, management would reevaluate whether to proceed with the NUG buydown agreements.

UNAMORTIZED PSNH ACQUISITION COSTS

The Rate Agreement also provides for the recovery by PSNH through rates of unamortized PSNH acquisition costs, which is the aggregate value placed by PSNH's reorganization plan on PSNH's assets in excess of the net book value of its non-Seabrook assets and the value assigned to Seabrook. The unrecovered balance of the unamortized PSNH acquisition costs at December 31, 1995 was approximately $588.9 million. In accordance with the Rate Agreement, approximately $143 million of this amount is scheduled to be amortized and recovered through rates by 1998, and the remaining amount, approximately $446 million, is being amortized and will be recovered through rates by 2011. PSNH earns a return each year on the unamortized portion of the cost. For more information regarding PSNH's recovery of these costs after 1997, see "Unamortized PSNH Acquisition Costs" in the notes to NU's financial statements and "Unamortized Acquisition Costs" in the notes to PSNH's financial statements.

DEMAND-SIDE MANAGEMENT/LEAST COST PLANNING

On January 29, 1996, the NHPUC approved a settlement in PSNH's DSM proceeding authorizing a 1996 budget of approximately $4.3 million, including direct program costs plus the recovery of certain lost revenues attributable to the program of approximately $2.8 million.

On April 10, 1995, in connection with PSNH's 1994 integrated least-cost resource plan filing, the NHPUC ordered PSNH to conduct future least-cost planning by evaluating resource options available to PSNH based on the economics of only the PSNH system, rather than the combined NU system. This ruling could have an adverse effect on the System's future resource planning.

SEABROOK POWER CONTRACTS

PSNH and NAEC have entered into two power contracts that obligate PSNH to purchase NAEC's 35.98 percent ownership of the capacity and output of Seabrook for the term of Seabrook's NRC operating license and to pay NAEC's "cost of service" during this period, whether or not Seabrook continues to operate. NAEC's cost of service includes all of its prudently incurred Seabrook-related costs, including maintenance and operation expenses, cost of fuel, depreciation of NAEC's recoverable investment in Seabrook and a phased-in return on that investment. The payments by PSNH to NAEC under these contracts constitute purchased power costs for purposes of the FPPAC and are recovered from customers under the Rate Agreement. Decommissioning costs are separately collected by PSNH in its base rates. See "Rates-New Hampshire Retail Rate-General" and "-FPPAC" for information relating to the Rate Agreement. At December 31, 1995, NAEC's net utility plant investment in Seabrook was approximately $707.1 million.

If Seabrook were retired prior to the expiration of its NRC operating license term, NAEC would continue to be entitled under the contracts to recover its remaining Seabrook investment and a return on that investment and its other Seabrook-related costs over a 39-year period, less the period during which Seabrook has operated.

The contracts provide that NAEC's return on its "allowed investment" in Seabrook (its investment in working capital, fuel, capital additions after the date of commercial operation and a portion of the initial investment) is calculated based on NAEC's actual capitalization over the term of the contracts, its actual debt and preferred equity costs and a common equity cost of 12.53 percent for the first ten years of the contracts, and thereafter at an equity rate of return to be fixed in a filing with FERC. The portion of the initial investment, which is included in the allowed investment, has increased annually since May 1991 and will reach 100 percent by May 31, 1996. As of December 31, 1995, 85 percent of the initial investment was included in rates.

NAEC is entitled to earn a deferred return on the portion of the initial investment not yet phased into rates. The deferred return on the excluded portion of the initial investment, together with a return on it, will be recovered between 1997 and 2001. At December 31, 1995, the amount of this deferred return was $162.4 million. For additional information regarding the contracts, see "Seabrook Power Contracts" in the notes to PSNH's financial statements.

MASSACHUSETTS RETAIL RATES

GENERAL

WMECO's retail rates are subject to the jurisdiction of the DPU. The rates charged under HWP's contracts with industrial customers are not subject to the ratemaking jurisdiction of any state or federal regulatory agency.

In 1994, the DPU approved a settlement offer from WMECO and the Massachusetts Attorney General (AG) that, among other things, provided that WMECO's customers' overall bills would be reduced by approximately $13.3 million over a 20-month period from June 1, 1994 to January 31, 1996. Under the 1994 settlement agreement, base rates would revert to their pre-settlement level after February 1, 1996, resulting in a 2.4 percent rate increase. WMECO, however, did not increase its rates on February 1, 1996, pending settlement negotiations.

On February 27, 1996, WMECO and the AG submitted a proposed settlement to the DPU that would continue the rate reduction first instituted in June 1994. The settlement provides, among other things, that WMECO's rates remain about 2.4 percent lower than otherwise authorized (a reduction of approximately $8 million per year) through February 1998. In addition, the agreement accelerates WMECO's recovery of strandable costs by an additional $5.8 million in 1996 and $10 million in 1997. The terms of the settlement were put into effect as of March 1, 1996, but are subject to final DPU approval.

ELECTRIC INDUSTRY RESTRUCTURING IN MASSACHUSETTS

In February 1995, the DPU began an investigation into electric industry restructuring in Massachusetts. On March 31, 1995, WMECO submitted its plan for the future of the electric industry entitled "Path To A Competitive Future" to the DPU. WMECO's comments paralleled those submitted by CL&P to the DPUC in March 1995. See "Rates-Connecticut Retail Rates-Electric Industry Restructuring in Connecticut." On August 16, 1995, the DPU found that it was in the public interest that electric utilities have an opportunity to recover net, nonmitigatable strandable costs during a transition to full competition, which period is to be no longer than ten years. Strandable costs are to be recovered by a mandatory charge. The DPU also ordered WMECO and two other Massachusetts utilities to submit, by February 16, 1996, plans for moving to a competitive generation market, retail choice of electric suppliers and incentive regulation for transmission and distribution.

On February 16, 1996, WMECO filed its restructuring plan with the DPU. WMECO's plan, if implemented, would institute a stable five-year rate path based on performance incentives; a universal service charge to recover "net" strandable costs; a comprehensive approach to pay off rapidly strandable costs; and rate design modifications that reflect more market influence. In addition, WMECO's plan would put into place the structural changes needed for a more competitive retail marketplace by proposing illustrative rates which unbundle charges for generation, distribution, transmission and ancillary services; building the information system necessary to provide customers the data to make informed choices within a competitive market; developing rules necessary to provide fair competition and adequate customer protection in a competitive retail market; and proposing pilot programs to test customer choice of alternate suppliers of energy.

Several other utilities and the Massachusetts Division of Energy Resources (DOER) also filed restructuring plans with the DPU. The DOER plan requires, among other things, (i) total retail choice by January 1, 1998; (ii) the separation of presently regulated electric utility into unregulated generation and regulated distribution companies by January 1, 2001; and (iii) the use of a market-based valuation process (e.g., auction) for identifying and mitigating strandable costs. A final schedule for implementation of a Massachusetts restructuring plan has not yet been issued.

WMECO FUEL ADJUSTMENT CLAUSE AND GENERATING UNIT OPERATING PERFORMANCE

In Massachusetts, all fuel costs are collected on a current basis by means of a forecasted semi-annual fuel clause, which is trued up periodically. The DPU must hold public hearings before permitting semi-annual adjustments in WMECO's retail fuel adjustment clause. In addition to energy costs, the fuel adjustment clause includes capacity and transmission charges and credits that result from short-term transactions with other utilities and from certain FERC-approved contracts among the System operating companies.

Massachusetts law establishes an annual performance program related to fuel procurement and use and requires the DPU to review generating unit performance and related fuel costs. Fuel clause revenues collected in Massachusetts are subject to potential refund, pending the DPU's examination of the actual performance of WMECO's generating units. The DPU has found that possession of a minority ownership interest in a generating plant does not relieve a company of its responsibilities for the prudent operation of that plant. Accordingly, the DPU has established goals for the three Millstone units and for the three regional nuclear operating units (the Yankee plants) in which WMECO has ownership interests.

The DPU has initiated prudence reviews of WMECO's 1993-1994 and 1994-1995 generating unit performances. Pursuant to the terms of the February 27, 1996 settlement proposal discussed above and subject to DPU approval, these prudence reviews would be terminated. In addition the settlement precludes any prudence review concerning the extended 1994-1995 Millstone 2 outage.

DEMAND-SIDE MANAGEMENT

In 1992, the DPU established a conservation charge (CC) to be included in WMECO's customers' bills. The CC includes incremental DSM program costs above or below base rate recovery levels, lost fixed-cost recovery adjustments and the provision for a DSM incentive mechanism.

On August 24, 1995 and November 27, 1995, the DPU issued decisions limiting WMECO's recovery of lost base revenues in calendar year 1996 to those revenues lost due to implementation of conservation-related costs in the most recent three-year period. The DPU decision did not affect 1995 revenues, but the three-year limit on recovery is expected to reduce 1996 revenues by approximately $5.5 million.

On January 17, 1996, the DPU approved a two-year settlement proposal that resolves WMECO's DSM-related proceedings before the DPU. The settlement resolves: (i) DSM budget levels for 1996 and 1997 (at $12.4 million and $11.9 million, respectively); (ii) the CC for each rate class for 1996 and 1997; and (iii) energy savings associated with past DSM activity. The DSM budget levels agreed upon for 1996 and 1997 are considerably lower than the $15.8 million in effect for 1995.

The February 27, 1996 settlement proposal of WMECO and the AG, however, modifies, in part, the above-referenced DSM decisions. If approved by the DPU, the settlement would shift $8 million now included in the CC as lost base revenues into base rates.

RESOURCE PLANS

CONSTRUCTION

The System's construction program in the period 1996 through 2000 is estimated as follows:

	1996	1997	1998	1999	2000
			(Millions)		
CL&P	$154.6	$172.9	$155.3	$146.0	$147.6
PSNH	51.5	38.2	36.9	41.8	32.5
WMECO	30.4	44.2	42.4	34.0	33.8
NAEC	6.0	6.6	6.9	7.2	7.4
OTHER	22.6	5.1	3.2	2.0	1.9
TOTAL	$265.1	$267.0	$244.7	$231.0	$223.2

The construction program data shown above include all anticipated capital costs necessary for committed projects and for those reasonably expected to become committed, regardless of whether the need for the project arises from environmental compliance, nuclear safety, reliability requirements or other causes. The construction program's main focus is maintaining and upgrading the existing transmission and distribution system and nuclear and fossil-generating facilities.

The construction program data shown above generally include the anticipated capital costs necessary for fossil generating units to operate at least until their scheduled retirement dates. Whether a unit will be operated beyond its scheduled retirement date, be deactivated or be retired on or before its scheduled retirement date is regularly evaluated in light of the System's needs for resources at the time, the cost and availability of alternatives and the costs and benefits of operating the unit compared with the costs and benefits of retiring the unit. Retirement of certain of the units could, in turn, require substantial compensating expenditures for other parts of the System's bulk power supply system. Those compensating capital expenditures have not been fully identified or evaluated and are not included in the table.

FUTURE NEEDS

The System periodically updates its long-range resource needs through its integrated demand and supply planning process. The System does not foresee the need for any new major generating facilities at least until 2011.

The System's long-term plans rely, in part, on certain DSM programs. These System company sponsored measures, including installations to date, are projected to lower the System summer peak load in 2011 by 752 MW and lower the winter peak load as of January 1, 2012 by 495 MW. See "Rates" for information about rate treatment of DSM costs.

In addition, System companies have long-term arrangements to purchase the output from certain NUGs under federal and state laws, regulations and orders mandating such purchases. NUGs supplied 649 MW of firm capacity in 1995. This is the maximum amount that the System companies expect to purchase from NUGs for the foreseeable future. See "Rates-New Hampshire Retail Rates- NUGs" for information concerning PSNH's efforts to renegotiate its agreements with 13 NUGs and "CL&P Cogeneration Costs" in the notes to NU's financial statements and "Cogeneration Costs" in the notes to CL&P's financial statements for information regarding CL&P's termination of one of its purchased-power agreements.

The System's long-term resource plan also considers the economic viability of continuing the operation of certain of the System's fossil fuel generating units beyond their current book retirement dates. Continued operation of existing fossil fuel units past their book retirement dates (and replacing certain critically located peaking units if they fail) is expected to provide approximately 2,300 MW of resources by 2011 that would otherwise have been retired.

The System's need for new resources may be affected by unscheduled retirements of its existing generating units, regulatory approval of the continued operation of fossil fuel units and nuclear units past scheduled retirement dates and deactivation of plants resulting from environmental compliance or licensing decisions.

FINANCING PROGRAM

1995 FINANCINGS

On January 23, 1995, CL&P Capital, L.P. (CL&P LP) issued $100 million of 9.3 percent Cumulative Monthly Income Preferred Securities (MIPS), Series A. CL&P is the sole general partner of CL&P LP and is the guarantor of the MIPS securities. The net proceeds from the issuance and sale of MIPS, along with the proceeds of short-term debt, were used to retire $67.5 million of CL&P's 1989 Series 9 percent preferred stock and $50 million of variable-rate 1989 Dutch Auction Rate Transferable Securities.

In December 1995, NAEC completed a $225 million variable rate note facility with a group of banks. NAEC retired $205 million principal amount of its 15.23 percent notes, due 2000, in early November 1995, with funding in early December 1995 from the proceeds of the variable rate note facility. Interest rate swap agreements were entered into to effectively convert the interest rate on the new notes from variable to fixed. Under the terms of the interest rate swap agreements, the effective interest rate on the new notes is 7.05 percent. The refinancing is expected to save approximately $4 million annually over the next five years.

Total System debt, including short-term and capitalized leased obligations, was $4.25 billion as of December 31, 1995, compared with $4.54 billion as of December 31, 1994 and $4.88 billion as of December 31, 1993. For more information regarding 1995 financings, see Notes to Consolidated Statements of Capitalization of NU's financial statements and "Short-Term Debt" in the notes to CL&P's, PSNH's, WMECO's and NAEC's financial statements.

1996 FINANCING REQUIREMENTS

The System's aggregate capital requirements for 1996, exclusive of requirements under the Niantic Bay Fuel Trust (NBFT) and a one percent sinking and improvement fund for CL&P and WMECO, are as follows:

	CL&P	PSNH	WMECO (Millions)	NAEC	Other	Total System
Construction...........	$154.6	$51.5	$30.4	$6.0	$22.6	$265.1
Nuclear Fuel......	-	1.8	-	0.6	-	2.4
Maturities.............	-	172.5	-	-	-	172.5
Cash Sinking-funds.....	9.4	-	1.5	20.0	16.3	47.2
Total............	$164.0	$225.8	$31.9	$26.6	$38.9	$487.2

For further information on NBFT and the System's financing of its nuclear fuel requirements, see "Leases" in the notes to NU's, CL&P's and WMECO's financial statements. For further information on the System's 1996 and five-year financing requirements, see "Notes to Consolidated Statements of Capitalization" in NU's financial statements and "Long-Term Debt" in the notes to CL&P's, PSNH's and WMECO's financial statements.

1996 FINANCING PLANS

The System Companies propose to finance their 1996 requirements, through both internal cash flow and external funds, with internally generated funds expected to provide substantially all of the necessary funds for the System. This estimate excludes the nuclear fuel requirements financed through the NBFT and any additional financing needed in connection with the PSNH NUGs settlements, but includes assumed funding of liability for prior spent nuclear fuel in the amounts of $160.2 million for CL&P and $38.6 million for WMECO. For more information regarding the NUGs settlements, see "Rates-New Hampshire Retail Rates-NUGs." In addition to financing their 1996 requirements, the System companies intend, if market conditions permit, to continue to refinance a portion of their outstanding long-term debt and preferred stock, if that can be done advantageously.

In April 1995, NU began issuing NU common stock to fund its Dividend Reinvestment Plan (DRP). The total amount financed through the DRP in 1995 was approximately $41 million. NU expects to raise approximately the same amount of capital through the DRP in 1996.

CL&P intends to issue through the Connecticut Development Authority $62 million principal amount of Pollution Control Revenue Bonds in the first half of 1996. The net proceeds of these bonds will be used to reimburse CL&P for its share of the cost of pollution control and solid waste disposal facilities at Millstone 3. PSNH also intends to establish a new $225 million revolving credit agreement in the second quarter of 1996 to replace its existing $125 million revolving credit agreement, which expires in May 1996. This credit facility will be used by PSNH primarily for refunding of a $172.5 million principal amount issue of maturing first mortgage bonds and for working capital purposes.

On October 18, 1995, Moody's Investors Service lowered its ratings of PSNH and NAEC securities, bringing the rating for PSNH's First Mortgage Bonds below investment grade. Standard and Poor's had previously downgraded PSNH's first mortgage bonds below investment grade. NAEC's securities have never been rated investment grade by either agency. With both of the major nationally recognized securities rating organizations that rate PSNH and NAEC securities rating them below investment grade, PSNH's and NAEC's borrowing costs have increased and the future availability and cost of funds for those companies could be restricted.

FINANCING LIMITATIONS

The amounts of short-term borrowings that may be incurred by NU, CL&P, PSNH, WMECO, HWP and NAEC are subject to periodic approval by the SEC under the 1935 Act. Effective June 28, 1995, the SEC no longer regulates the short-term borrowings of NU's non-utility subsidiary companies from nonaffiliates or through the Northeast Utilities System Money Pool (Money Pool).

The following table shows the amount of short-term borrowings authorized by the SEC for each company as of January 1, 1996 and the amounts of outstanding short-term debt of those companies at the end of 1995.

	Maximum Authorized Short-Term Debt	Short-Term Debt Outstanding at 12/31/95*
	(Millions)	
NU..................	$ 150	$ 58
CL&P	325	52
PSNH	175	-
WMECO...............	60	24
HWP.................	5	-
NAEC................	50	8
NNECO...............	**	-
RRR.................	**	17
Quinnehtuk..........	**	5
HEC.................	**	2
	Total	$ 166

* This column includes borrowings of various System companies from NU and other System companies through the Money Pool. Total System short-term indebtedness to unaffiliated lenders was $99 million at December 31, 1995.

** Effective June 28, 1995, the SEC no longer regulates the short-term debt issuances of these companies.

The supplemental indentures under which NU issued $175 million in principal amount of 8.58 percent amortizing notes in December 1991 and $75 million in principal amount of 8.38 percent amortizing notes in March 1992 contain restrictions on dispositions of certain System companies' stock, limitations of liens on NU assets and restrictions on distributions on and acquisitions of NU stock. Under these provisions, neither NU, CL&P, PSNH nor WMECO may dispose of voting stock of CL&P, PSNH or WMECO other than to NU or another System company, except that CL&P may sell voting stock for cash to third persons if so ordered by a regulatory agency so long as the amount sold is not more than 19 percent of CL&P's voting stock after the sale. The restrictions also generally prohibit NU from pledging voting stock of CL&P, PSNH or WMECO or granting liens on its other assets in amounts greater than 5 percent of the total common equity of NU. As of December 31, 1995, no NU debt was secured by liens on NU assets. Finally, NU may not declare or make distributions on its capital stock, acquire its capital stock (or rights thereto), or permit a System company to do the same, at times when there is an event of default under the supplemental indentures under which the amortizing notes were issued.

The charters of CL&P and WMECO contain preferred stock provisions restricting the amount of unsecured debt those companies may incur. As of December 31, 1995, CL&P's charter would permit CL&P to incur an additional $466 million of unsecured debt and WMECO's charter would permit it to incur an additional $112 million of unsecured debt.

In connection with NU's acquisition of PSNH, certain financial conditions intended to prevent NU from relying on CL&P resources if the PSNH acquisition strains NU's financial condition were imposed by the DPUC. The principal conditions provide for a DPUC review if CL&P's common equity falls to 36 percent or below, require NU to obtain DPUC approval to secure NU financings with CL&P stock or assets and obligate NU to use its best efforts to sell CL&P preferred or common stock to the public if NU cannot meet CL&P's need for equity capital. At December 31, 1995, CL&P's common equity ratio was 42.8 percent.

While not directly restricting the amount of short-term debt that CL&P, WMECO, RRR, NNECO and NU may incur, credit agreements to which CL&P, WMECO, HWP, RRR, NNECO and NU are parties provide that the lenders are not required to make additional loans, or that the maturity of indebtedness can be accelerated, if NU (on a consolidated basis) does not meet a common equity ratio test that requires, in effect, that NU's consolidated common equity (as defined) be at least 30 percent for three consecutive quarters. At December 31, 1995, NU's common equity ratio was 35.7 percent.

Under a certain credit agreement, PSNH is prohibited from incurring additional debt unless it is able to demonstrate, on a pro forma basis for the prior quarter and going forward, that its equity ratio (as defined) will be at least 27 percent of total capitalization (as defined) through June 30, 1996 and 28.5 percent through June 30, 1997. In addition, PSNH must demonstrate that its ratio of operating income to interest expense will be at least 1.75 to 1 for the end of each fiscal quarter for the remaining term of the agreement. At December 31, 1995, PSNH's common equity ratio was 36.4 percent and its operating income to interest expense ratio for the 12-month period was 2.74 to 1.

During 1995, NAEC entered into a credit agreement that prohibits the incurrence of additional debt unless NAEC demonstrates that at all times its common equity (as defined) will be at least 25 percent and its ratio of adjusted net income (as defined) to interest expense will be at least 1.35 to 1 through December 31, 1997 and 1.50 to 1 thereafter. At December 31, 1995, NAEC's common equity ratio was 28.3 percent and its adjusted net income to interest expense ratio for the 12-month period was 1.51 to 1.

See "Short-Term Debt" in the notes to NU's, CL&P's, PSNH's and WMECO's financial statements for information about credit lines available to System companies.

The indentures securing the outstanding first mortgage bonds of CL&P, PSNH, WMECO and NAEC provide that additional bonds may not be issued, except for certain refunding purposes, unless earnings (as defined in each indenture and before income taxes, and, in the case of PSNH, without deducting the amortization of PSNH's regulatory asset) are at least twice the pro forma annual interest charges on outstanding bonds and certain prior lien obligations and the bonds to be issued.

The preferred stock provisions of CL&P's, PSNH's and WMECO's charters also prohibit the issuance of additional preferred stock (except for refinancing purposes) unless income before interest charges (as defined and after income taxes and depreciation) is at least 1.5 times the pro forma annual interest charges on indebtedness and the annual dividend requirements on preferred stock that will be outstanding after the additional stock is issued.

NU is dependent on the earnings of, and dividends received from, its subsidiaries to meet its own financial requirements, including the payment of dividends on NU common shares. At the current indicated annual dividend of $1.76 per share, NU's aggregate annual dividends on common shares outstanding at December 31, 1995, including unallocated shares held by the Employee Stock Option Plan, would be approximately $239 million. Dividends are payable on common shares only if, and in the amounts, declared by the NU Board of Trustees.

SEC rules under the 1935 Act require that dividends on NU's shares be based on the amounts of dividends received from subsidiaries, not on the undistributed retained earnings of subsidiaries. The SEC's order approving NU's acquisition of PSNH under the 1935 Act approved NU's request for a waiver of this requirement through June 1997. PSNH and NAEC were effectively prohibited from paying dividends to NU through May 1993. Through the remainder of 1993 and 1994, PSNH did not pay dividends, to allow it to build up the common equity portion of its capitalization and to fund the buyout of certain NUGs operating in New Hampshire. See "Rates—New Hampshire Retail Rates—FPPAC and NUGs." PSNH and NAEC paid dividends to NU of $52 million and $24 million, respectively, in 1995. If PSNH does not fund its pro rata share of NU's dividend requirements, NU expects to fund that portion of its dividend requirements with the proceeds of borrowings.

The supplemental indentures under which CL&P's and WMECO's first mortgage bonds and the indenture under which PSNH's first mortgage bonds have been issued limit the amount of cash dividends and other distributions these subsidiaries can make to NU out of their retained earnings. As of December 31, 1995, CL&P had $245.3 million, WMECO had $93.8 million and

PSNH had $143.0 million of unrestricted retained earnings. PSNH's preferred stock provisions also limit the amount of cash dividends and other distributions PSNH can make to NU if after taking the dividend or other distribution into account, PSNH's common stock equity is less than 25 percent of total capitalization. The indenture under which NAEC's Series A Bonds have been issued also limits the amount of cash dividends or distributions NAEC can make to NU to retained earnings plus $10 million. At December 31, 1995, $69.6 million was available to be paid under this provision.

PSNH's credit agreement prohibits it from declaring or paying any cash dividends or distributions on any of its capital stock, except for dividends on the preferred stock, unless minimum interest coverage and common equity ratio tests are satisfied. At December 31, 1995, $201 million was available to be paid under these provisions. NAEC's common equity covenant referred to above could also operate to restrict NAEC's ability to pay common dividends.

Certain subsidiaries of NU established the Money Pool to provide a more effective use of the cash resources of the System and to reduce outside short-term borrowings. NUSCO administers the Money Pool as agent for the participating companies. Short-Term borrowing needs of the participating companies (except NU) are first met with available funds of other member companies, including funds borrowed by NU from third parties. NU may lend to, but not borrow from, the Money Pool. Investing and borrowing subsidiaries receive or pay interest based on the average daily Federal Funds rate, except that borrowings based on loans from NU bear interest at NU's cost. Funds may be withdrawn or repaid to the Money Pool at any time without prior notice.

ELECTRIC OPERATIONS

DISTRIBUTION AND LOAD

The System companies own and operate a fully integrated electric utility business. The System operating companies' retail electric service territories cover approximately 11,335 square miles (4,400 in CL&P's service area, 5,445 in PSNH's service area and 1,490 in WMECO's service area) and have an estimated total population of approximately 4 million (2.5 million in Connecticut, 963,000 in New Hampshire and 582,000 in Massachusetts). The companies furnish retail electric service in 149, 198 and 59 cities and towns in Connecticut, New Hampshire and Massachusetts, respectively. In December 1995, CL&P furnished retail electric service to approximately 1.1 million customers in Connecticut, PSNH provided retail electric service to approximately 405,000 customers in New Hampshire and WMECO served approximately 194,000 retail electric customers in Massachusetts. HWP serves 38 retail customers in Holyoke, Massachusetts.

The following table shows the sources of 1995 electric revenues based on categories of customers:

	CL&P	PSNH	WMECO	NAEC	Total System
Residential........	41%	34%	37%	-	37%
Commercial..........	35	29	32	-	31
Industrial	13	18	20	-	15
Wholesale*	8	17	7	100%	14
Other	3	2	4	-	3
Total	100%	100%	100%	100%	100%

* Includes capacity sales.

NAEC's 1995 electric revenues were derived entirely from sales to PSNH under the Seabrook power contracts. See "Rates-New Hampshire Retail Rates-Seabrook Power Contracts" for a discussion of the contracts.

Through December 31, 1995, the all-time peak demand on the System was 6,358 MW, which occurred on August 2, 1995. The System was also selling approximately 1,217 MW of capacity to other utilities at that time. At the time of the peak, the System's generating capacity, including capacity purchases, was 8,035 MW.

System energy requirements were met in 1995 and 1994 as set forth below:

Source	1995	1994
Nuclear	52%	54%
Oil	4	7
Coal	10	8
Hydroelectric	3	4
Natural gas	5	3
NUGs	13	14
Purchased-power...........................	13	10
	100%	100%

The actual changes in retail KWh sales for the last two years and the forecasted sales growth estimates for the ten-year period 1995 through 2005, in each case exclusive of wholesale revenues, for the System, CL&P, PSNH and WMECO are set forth below:

	1995 over 1994	1994 over 1993	Forecast 1995-2005 Compound Rate of Growth
System.........	(.1)%	2.9%	1.2%
CL&P...........	(.3)%	3.4%	1.1%
PSNH...........	.4 %	2.0%	1.6%
WMECO..........	(.1)%	1.4%	0.6%

The actual changes in total KWh sales for the last two years, including wholesale KWh sales, for the System, CL&P, PSNH and WMECO are set forth below:

	1995 over (under) 1994	1994 over (under) 1993
System	(1.24)%	2.53%
CL&P	(2.21)%	3.66%
PSNH	1.08 %	1.70%
WMECO	0.33 %	1.49%

For a discussion of trends in wholesale sales, see "Competition and Marketing-Wholesale Marketing."

The combination of much milder winter temperatures and slower economic growth caused retail electric sales to fall by 0.1 percent in 1995, compared with 1994. The most significant reduction was in residential electric sales, which are most affected by summer and winter temperature variations. Residential sales were down 1.8 percent in 1995. By comparison, commercial sales were up by .8 percent for the year and industrial sales rose 1.7 percent. Had weather patterns in 1995 been similar to those in 1994, the System estimates its total retail sales would have risen by 0.3 percent.

The reduced level of retail sales also resulted from a continued slowdown of economic growth in New England, particularly in Connecticut. Retail sales at CL&P fell by 0.3 percent in 1995. If weather effects were removed, CL&P's sales would have been flat when compared with 1994. The lack of growth is primarily attributable to the continued contraction of the manufacturing, defense, insurance and financial services sectors in Connecticut. PSNH's retail sales rose by 0.4 percent in 1995, largely because of a 4.4 percent increase in industrial sales. Higher industrial sales were due primarily to the continued growth of manufacturing activity in New Hampshire and a summer drought that reduced hydroelectric self-generation by some of PSNH's larger customers. WMECO retail sales were essentially flat in 1995 with 2.6 percent growth in commercial sales partially offsetting lower residential sales. For more information on the effect of competition on sales growth rates, see "Competition and Marketing."

In spite of further defense and insurance curtailments moderate growth is forecasted to resume over the next ten years. The System forecasts a 1.0 percent growth rate of sales over this period. This growth rate is significantly below historic rates due to fewer young people entering the workforce and, in part, because of forecasted savings from System-sponsored DSM programs that are designed to minimize operating expenses for System customers and postpone the need for new capacity on the System. The forecasted ten-year growth rate of System sales would be approximately 1.5 percent if the System did not pursue DSM programs at the forecasted levels. See "Rates" for information about rate treatment of DSM costs.

With the System's generating capacity of 7,956 MW as of January 1, 1996 (including the net of capacity sales to and purchases from other utilities, and approximately 649 MW of capacity purchased from NUGs under existing contracts), the System expects to meet reliably its projected annual peak load growth of 1.0 percent until at least the year 2011.

Taking into account projected load growth for the System and committed capacity sales, but not taking into account future potential capacity sales to other utilities or purchases from other utilities that are not subject to firm commitments, the System's installed reserve is expected to be approximately 1,614 MW in the summer of 1996.

The System companies operate and dispatch their generation as provided in the NEPOOL Agreement. In 1995, the peak demand on the NEPOOL system was 20,499 MW in July, which was 20 MW below the 1994 peak load of 20,519 MW in July of that year. NEPOOL has projected that there will be an increase in demand in 1996 and estimates that the summer 1996 peak load could reach 22,368 MW. NEPOOL projects that sufficient capacity will be available to meet this anticipated demand.

REGIONAL AND SYSTEM COORDINATION

The System companies and most other New England utilities with electric generating facilities are parties to the NEPOOL Agreement, which coordinates the planning and operation of the region's generation and transmission facilities. System transmission lines form part of the New England transmission system linking System generating plants with one another and with the facilities of other utilities in the Northeastern United States and Canada. The generating facilities of all NEPOOL participants are dispatched as a single system through the New England Power Exchange, a central dispatch facility. The NEPOOL Agreement provides for a determination of the generating capacity responsibilities of participants and certain transmission rights and responsibilities. NEPOOL's objectives are to assure that the bulk power supply of New England and adjoining areas conforms to proper standards of reliability, to attain maximum practical economy in the bulk power supply system consistent with such reliability standards and to provide for equitable sharing of the resulting benefits and costs.

Since 1994, NEPOOL has been studying its own restructuring. On January 5, 1996, NEPOOL adopted a vision statement for the future called "NEPOOL Plus." NEPOOL Plus, if implemented, will maintain the pool's current strengths and adds key structural changes, including bid-based central energy dispatch, a changed and expanded basis for governance and increased independence of the operational function of NEPOOL staff as an independent system operator. The final NEPOOL restructuring plan will be subject to approval by FERC. Representatives of the System played an active role in the development of the plan. The System believes that NEPOOL Plus is an important component of electric industry restructuring in New England, providing the basis for a more efficient wholesale market for electricity and offering the potential for retail market efficiencies in the future.

There are two agreements that determine the manner in which costs and savings are allocated among the System companies. Under the NUG&T, CL&P, WMECO and HWP (Initial System Companies) pool their electric production costs and the costs of their principal transmission facilities. Pursuant to the merger agreement, the Initial System Companies and PSNH entered into a ten-year, sharing agreement, expiring in June 2002, that provides, among other things, for the allocation of the capability responsibility savings and energy expense savings resulting from a single-system dispatch through NEPOOL.

TRANSMISSION ACCESS

In accordance with FERC's 1992 decision approving NU's acquisition of PSNH, NU made compliance filings with FERC, including transmission tariffs. FERC made all tariffs effective as of the merger date based on interim rates and terms of service established by FERC pursuant to summary determinations (without hearing). NU filed for rehearing of FERC's compliance tariff order in an effort to reinstate the originally proposed rates. FERC has not yet acted on NU's rehearing petition. In 1995, the System companies collected approximately $40 million in transmission revenues for transmission of power sales for the System companies and other electric utility generators. For information regarding the appeal of FERC's approval of NU's acquisition of PSNH, see "Item 3. Legal Proceedings."

On March 29, 1995, FERC issued a Notice of Proposed Rulemaking (Mega-NOPR) on industry restructuring that would require, among other things, utilities to provide transmission access and certain ancillary services on the same terms as the utility provides those services to itself. The Mega-NOPR also supports full recovery of strandable costs as a result of retail wheeling with respect to those customers under FERC's jurisdiction. A final rule is not expected until June 1996.

On September 5, 1995, the System filed with FERC its four transmission tariffs to meet the comparability standards articulated in the Mega-NOPR. On October 31, 1995, FERC accepted for filing the System's revised transmission tariffs and made them effective November 1, 1995. In the order, however, FERC noted that certain terms and conditions for such tariffs were not fully consistent with the Mega-NOPR pro forma tariffs and made the tariffs subject to the final order in its Mega-NOPR proceeding. FERC also stated that the System may use levelized rates rather than previously used depreciated embedded cost rate methods. On February 29, 1996, NU filed a settlement with FERC in this proceeding. The settlement resolves all issues except two rate design issues, which will be resolved through expedited paper hearing procedures over the next several months. If NU's rate design is confirmed, the System could collect approximately $2 million of additional transmission revenues annually.

FOSSIL FUELS

The System's residual oil-fired generation stations used approximately 5.6 million barrels of oil in 1995. The System obtained the majority of its oil requirements in 1995 through contracts with several large, independent oil companies. Those contracts allow for some spot purchases when market conditions warrant. Spot purchases represented approximately 10 percent of the System's fuel oil purchases in 1995. The contracts expire annually or biennially. The System currently does not anticipate any difficulties in obtaining necessary fuel oil supplies on economic terms.

The System has five generating stations, aggregating approximately 800 MW, which can fully or partially burn either residual oil or natural gas/coals, as economics, environmental concerns or other factors dictate. CL&P is considering converting its oil-fired Middletown Station in Connecticut to a dual-fuel generating facility. Approximately 551 MW of capacity is capable of being converted at the Middletown Station. CL&P,

PSNH and WMECO have contracts with the local gas distribution companies where the dual-fuel generating units are located, under which natural gas is made available by those companies on an interruptible basis. In addition, gas for CL&P'S Devon and Montville generating stations is being purchased directly from producers and brokers on an interruptible basis and transported through the interstate pipeline system and the local gas distribution company. The System expects that interruptible natural gas will continue to be available for its dual-fuel electric generating units on economic terms and will continue to supplement fuel oil requirements.

See "Derivative Financial Instruments" in the notes to NU's and CL&P's financial statements for information about CL&P's oil and natural gas swap agreements that hedge against fuel price risk on certain long-term, fixed-price energy contracts.

The System companies obtain their coal through long-term supply contracts and spot market purchases. The System companies currently have an adequate supply of coal. Because of changes in federal and state air quality requirements, the System may be required to use lower sulfur coal in its plants in the future. See "Regulatory and Environmental Matters-Environmental Regulation-Air Quality Requirements."

NUCLEAR GENERATION

GENERAL

Certain System companies have interests in seven operating nuclear units: Millstone 1, 2 and 3, Seabrook 1 and three other units, Connecticut Yankee (CY), Maine Yankee (MY) and Vermont Yankee (VY), owned by regional nuclear generating companies (the Yankee companies). System companies operate the three Millstone units and Seabrook 1 and have operational responsibility for CY. Certain System companies also have interests in Yankee Rowe owned by the Yankee Atomic Electric Company (YAEC), which was permanently removed from service in 1992.

CL&P and WMECO own 100 percent of Millstone 1 and 2 as tenants in common. Their respective ownership interests are 81 percent and 19 percent.

CL&P, PSNH and WMECO have agreements with other New England utilities covering their joint ownership as tenants in common of Millstone 3. CL&P's ownership interest in the unit is 52.93 percent, PSNH's ownership interest in the unit is 2.85 percent and WMECO's interest is 12.24 percent. NAEC and CL&P have 35.98 percent and 4.06 percent ownership interests, respectively, in Seabrook. The Millstone 3 and Seabrook joint ownership agreements provide for pro-rata sharing by the owners of each unit of the construction and operating costs, the electrical output and the associated transmission costs.

CL&P, PSNH, WMECO and other New England electric utilities are the stockholders of the Yankee companies. Each Yankee company owns a single nuclear generating unit. The stockholder-sponsors of each Yankee company are responsible for proportional shares of the operating costs of the respective Yankee company and are entitled to proportional shares of the electrical output. The relative rights and obligations with respect to the Yankee companies are approximately proportional to the stockholders' percentage stock holdings, but vary slightly to reflect arrangements under which nonstockholder electric utilities have contractual rights to some of the output of particular units. The Yankee companies and CL&P's, PSNH's and WMECO's stock ownership percentages in the Yankee companies are set forth below:

	CL&P	PSNH	WMECO	System
Connecticut Yankee Atomic Power Company (CYAPC)	34.5%	5.0%	9.5%	49.0%
Maine Yankee Atomic Power Company (MYAPC)	12.0%	5.0%	3.0%	20.0%
Vermont Yankee Nuclear Power Corporation (VYNPC)...	9.5%	4.0%	2.5%	16.0%
Yankee Atomic Electric Company (YAEC)	24.5%	7.0%	7.0%	38.5%

CL&P, PSNH and WMECO are obligated to provide their percentages of any additional equity capital necessary for the Yankee companies, but do not expect to need to contribute additional equity capital in the future. CL&P, PSNH and WMECO believe that the Yankee companies, excluding YAEC, could require additional external financing in the next several years to finance construction expenditures, nuclear fuel and for other purposes. Although the ways in which each Yankee company would attempt to finance these expenditures, if they are needed, have not been determined, CL&P, PSNH and WMECO could be asked to provide direct or indirect financial support for one or more Yankee companies. For information regarding additional capital requirements at MY, see "Electric Operations-Nuclear Generation-Nuclear Plant Performance."

On February 1, 1996, the System instituted a reorganization of its nuclear organization that puts in place a six person team to lead the five nuclear units that the System operates. The new nuclear management team is in charge of overseeing safety, efficiency and community relations at all five nuclear units. The new structure pools the expertise and strengths from each unit to manage issues to be addressed at all the units.

NUCLEAR PLANT LICENSING AND NRC REGULATION

The operators of Millstone 1, 2 and 3, CY, MY, VY, and Seabrook 1 hold full power operating licenses from the NRC. As holders of licenses to operate nuclear reactors, CL&P, WMECO, NAESCO, NNECO, and the Yankee companies are subject to the jurisdiction of the NRC. The NRC has broad jurisdiction over the design, construction and operation of nuclear generating stations, including matters of public health and safety, financial qualifications, antitrust considerations and environmental impact. The NRC issues 40-year initial operating licenses to nuclear units and NRC regulations permit renewal of licenses for an additional 20-year period.

In addition, activities related to nuclear plant operation are routinely inspected by the NRC for compliance with NRC regulations. The NRC has authority to enforce its regulations through various mechanisms which include the issuance of notices of violation (NOV) and civil monetary penalties. One regulatory enforcement action, with an associated penalty of $50,000, was taken by the NRC in 1995 for certain violations involving the operability of motor-operated valves at Millstone 2.

The NRC also regularly conducts generic reviews of technical and other issues, a number of which may affect the nuclear plants in which System companies have interests. The cost of complying with any new requirements that may result from these reviews cannot be estimated at this time, but such costs could be substantial. For more information regarding recent actions taken by the NRC with respect to the System's nuclear units, see "Electric Operations-Nuclear Generation-Nuclear Plant Performance."

NUCLEAR PLANT PERFORMANCE

Capacity factor is a ratio that compares a unit's actual generating output for a period with the unit's maximum potential output. The average capacity factor for operating nuclear units in the United States was 77.6 percent in 1995 and 69.9 percent for the five nuclear units operated by the System in 1995, compared with 67.5 percent for 1994.

The System anticipates total expenditures in 1996 of approximately $425 million for operations and maintenance (O&M) and $55.5 million in capital improvements for the five nuclear plants that it operates.

When the nuclear units in which they have interests are out of service, CL&P, PSNH and WMECO need to generate and/or purchase replacement power. Recovery of replacement power costs is permitted, subject to prudence reviews, through the GUAC for CL&P, through FPPAC for PSNH and through a retail fuel adjustment clause for WMECO. For the status of regulatory and legal proceedings related to recovery of replacement power costs for the 1991-1995 period, see "Rates."

MILLSTONE UNITS

For the 12 months ended December 31, 1995, the three Millstone units' composite capacity factor was 64.5 percent, compared with a composite capacity factor of 66.4 percent for the 12 months ended December 31, 1994 and 79.3 percent for the same period in 1993.

On January 31, 1996, the NRC announced that the three Millstone nuclear units had been placed on its "watch list" because of long standing performance concerns that warranted "increased NRC attention until the licensee demonstrates a period of improved performance." The NRC listed a number of problems which have arisen since 1990 at Millstone Station, including licensed reactor operator requalification failures, repetitive improper maintenance causing an unisolable valve failure, problems with a supplemental leak collection release system, inadequate erosion-corrosion monitoring, untimely corrective action involving a heater drain tank recirculation line rupture, poor testing control causing an inadvertent drain-down of a reactor vessel, a high number of safety system failures, safety relief valve setpoint drift problems, untimely corrective actions for identified design deficiencies, failures to implement procedures which precipitated significant plant events and in some cases endangered plant staff and failure to comply with safety-related aspects of Millstone's Final Safety Analysis Report and portions of other requirements. Also mentioned were two instances of escalated enforcement actions by the NRC for harassment, intimidation and discrimination against employees raising safety concerns and a continuing high volume of employee allegations of safety concerns not being resolved appropriately by the System.

The NRC recognized that at present there are significant current variations in the performance of the three units, but the foregoing events, combined with a failure to sustain performance improvements across all three units and to resolve employee concerns, required continued close NRC monitoring of programs and performance at Millstone Station to assure development and implementation of effective corrective action programs. While the NRC did not specifically restrict operations of the Millstone units, management expects that the increased NRC attention will inevitably have effects and costs that cannot be accurately estimated at this time.

Management also plans to continue its extensive efforts already underway to address the NRC's concerns that employees at the Millstone Station are unable to raise nuclear safety issues to company supervisors and managers without fear of retaliation. Among the NRC's recent actions has been the establishment of a senior-level group to conduct an evaluation of the handling of Millstone employee concerns. In February 1996, the NRC also requested information regarding the process followed by the System in connection with its recent nuclear workforce reduction. Management shares the NRC's concerns in this area and is continuing to take steps to ensure that the environment at Millstone Station is one in which workers feel free to raise issues without fear of retaliation. For more information regarding the workforce reduction, see "Employees."

On March 7, 1996, NUSCO received two letters from the NRC: the first relates to Millstone 2 and the second concerns Millstone 3 and CY. The correspondence regarding Millstone 2 notes "a number of operability and design concerns" at the unit and requires NU to submit information to the NRC on what NU has done to ensure future operations at Millstone 2 will conform to NRC regulations and to the unit's operating license and Updated Final Safety Analysis Report (UFSAR). That information must be submitted at least seven days before Millstone 2 restarts subsequent to the outage described below. The second NRC letter requests reports by April 6, 1996 on actions taken to date and the System's plans and schedule to ensure that future operation of Millstone 3 and CY will conform to NRC regulations and the units' operating licenses and UFSARs. Management does not know at this time whether the NRC will request similar information and assurances regarding Seabrook.

Millstone 1, a 660-MW boiling-water reactor, has a license expiration date of October 6, 2010. In 1995, Millstone 1 operated at a 77.2 percent capacity factor. The unit began a planned refueling and maintenance outage on November 4, 1995. The original outage duration of 49 days has been extended to the middle to late part of the second quarter to complete overlay repairs on the reactor recirculation system and to respond to a December 1995 letter from the NRC requesting information regarding actions to be taken to ensure that future operations of Millstone 1 will be conducted in accordance with the terms and conditions of its operating license and NRC regulations. Total replacement-power costs for CL&P and WMECO are expected to be approximately $6.5 million per month. It is also estimated that CL&P and WMECO will incur an additional $20 million of O&M costs as a result of the extended outage. The recovery of the replacement power and O&M costs could be subject to refund as a result of prudence reviews in Connecticut or Massachusetts.

Petitions were filed with the NRC in August 1995 seeking enforcement and other sanctions against the System for its historic practice of off-loading the full reactor core at Millstone 1 during refueling outages, as well as certain refueling practices at the other Millstone units and Seabrook 1. The NRC initiated several investigations in response to the petitions. One of the investigations was completed by the NRC's Office of the Inspector General in December 1995, which issued four findings: two critical of the System and two critical of the NRC technical staff's oversight of the System.

In addition, several New England-based public interest groups have requested a hearing on a license amendment issued by the NRC for Millstone 1 which would explicitly authorize the full-core offload practice. The request for a hearing is pending before the NRC's Atomic Safety and Licensing Board, and hearings are expected to take place in 1996.

Millstone 2, a 870-MW pressurized-water reactor, has a license expiration date of July 31, 2015. In 1995, Millstone 2 operated at a 35.9 percent capacity factor. In October 1994, Millstone 2 was shut down for a planned two month refueling and maintenance outage, which was extended by eight months. The outage encountered several unexpected difficulties that lengthened the duration of the outage. The outage extension was primarily caused by a significant scope increase in service water system repairs and an extremely deliberate approach to the conduct of work during the early portion of the outage. The unit returned to service on August 4, 1995. Replacement-power costs and O&M costs attributable to the extension of the outage for CL&P and WMECO were approximately $85 million and $24 million, respectively. The replacement power costs were recovered as incurred for WMECO and are currently being recovered by CL&P through the GUAC. O&M costs were deferred and are being amortized through rates by both CL&P and WMECO. The recovery of the replacement power and O&M costs could be subject to refund as a result of prudence reviews in Connecticut.

Millstone 2 was shut down on February 21, 1996 as a result of an engineering evaluation that determined that some valves could be inoperable in certain emergency scenarios. With the unit already off-line, management has decided to move up a mid-cycle inspection outage that had previously been scheduled to begin in mid-April. Management does not know at this time whether the NRC's March 7, 1996 request for information discussed above will have a material impact on the restart schedule for Millstone 2 but does believe there will be an extension beyond the previously scheduled April 1995 restart date. For each month the unit is not in service, the System will incur approximately $8.5 million to $9 million for replacement power costs.

Millstone 3, a 1154-MW pressurized-water reactor, has a license expiration date of November 25, 2025. In 1995, Millstone 3 operated at a 80.5 percent capacity factor. The unit began a planned refueling outage on April 14, 1995, which ended on June 7, 1995.

SEABROOK

Seabrook 1, a 1148-MW pressurized-water reactor, has a license expiration date of October 17, 2026. The Seabrook operating license expires 40 years from the date of issuance of authorization to load fuel, which was about three and one-half years before Seabrook's full-power operating license was issued. The System will determine at the appropriate time whether to seek recapture of some or all of this period from the NRC and thus add up to an additional three and one-half years to the operating term for Seabrook. In 1995, Seabrook operated at a capacity factor of 83.2 percent. The unit began a planned refueling and maintenance outage on November 3, 1995, which ended on December 11, 1995, the shortest planned outage in the unit's operating history.

YANKEE UNITS

CONNECTICUT YANKEE

CY, a 582-MW pressurized-water reactor, has a license expiration date of June 29, 2007. In 1995, CY operated at a capacity factor of 72.6 percent. CY began a planned refueling and maintenance outage on January 28, 1995, which ended on April 19, 1995. The outage was extended by 31 days to inspect and replace service water piping and fan motor cables for the containment air recirculation fan cooler units.

MAINE YANKEE

MY, a 870-MW pressurized-water reactor, has a license expiration date of October 21, 2008. MY's operating license expires 40 years from the date of issuance of the construction permit, which was about four years before MY's full-power operating license was issued. At the appropriate time, MYAPC will determine whether to seek recapture of this construction period from the NRC and add it to the term of the MY operating license. In 1995, MY operated at a capacity factor of 2.6 percent.

MY was out of service from early February 1995 through January 16, 1996 for a routine refueling outage combined with the sleeving of MY's three steam generators, at a cost of approximately $30 million. By order issued on January 3, 1996, the NRC suspended MY's authority to operate at full power and limited MY to operating at 90 percent power pending the NRC's review and approval of a computer code application used at MY. CL&P, WMECO and PSNH incurred additional costs for replacement power (estimated at $1 million, $200,000 and $400,000, respectively, per month) as result of the extended outage.

VERMONT YANKEE

VY, a 514-MW boiling water reactor, has a license expiration date of March 21, 2012. In 1995, VY operated at a capacity factor of 83.4 percent. VY had a 40-day planned refueling outage during 1995, which ended on May 3, 1995.

YANKEE ROWE

In February 1992, YAEC's owners voted to shut down Yankee Rowe permanently based on an economic evaluation of the cost of a proposed safety review, the reduced demand for electricity in New England, the price of alternative energy sources and uncertainty about certain regulatory requirements. The power contracts between CL&P, PSNH, WMECO and YAEC permit YAEC to recover from each its proportional share of the Yankee Rowe shutdown and decommissioning costs. For more information regarding the decommissioning of Yankee Rowe, see "Electric Operations-Nuclear Generation-Decommissioning."

NUCLEAR INSURANCE

The NRC requires nuclear plant licensees to maintain a minimum of $1.06 billion in nuclear property and decontamination insurance coverage. The NRC requires that proceeds from the policy following an accident that exceed $100 million will first be applied to pay expenses. The insurance carried by the licensees of the Millstone units, Seabrook 1, CY, MY and VY meets the NRC's requirements. YAEC has obtained an exemption for the Yankee Rowe plant from the $1.06 billion requirement and currently carries $25 million of insurance that otherwise meets the requirements of the rule. For more information regarding nuclear insurance, see "Nuclear Insurance Contingencies" in the notes to NU's, CL&P's, PSNH's, WMECO's and NAEC's financial statements.

NUCLEAR FUEL

The supply of nuclear fuel for the System's existing units requires the procurement of uranium concentrates, followed by the conversion, enrichment and fabrication of the uranium into fuel assemblies suitable for use in the System's units. The majority of the System companies' uranium enrichment services requirements is provided under a long-term contract with the United States Enrichment Corporation (USEC), a wholly owned United States government corporation. The majority of Seabrook's uranium enrichment services requirements is furnished through a Russian trading company. The System expects that uranium concentrates and related services for the units operated by the System and for the other units in which the System companies are participating, that are not covered by existing contracts, will be available for the foreseeable future on reasonable terms and prices.

On August 10, 1995, NAESCO filed a complaint in the United States Court of Federal Claims challenging the propriety of the prices charged by the USEC for uranium enrichment services procured for Seabrook Station in 1993. The complaint is an appeal of the final decision rendered by the USEC contracting officer denying NAESCO's claims, which range from $2.5 to $5.3 million, and will likely be considered along with similar complaints that are pending before the court on behalf of 13 other utilities.

As a result of the Energy Policy Act, the United States commercial nuclear power industry is required to pay to the United States Department of Energy (DOE), through a special assessment for the costs of the decontamination and decommissioning of uranium enrichment plants owned by the United States government, no more than $150 million for 15 years beginning in 1993. Each domestic nuclear utility's payment is based on its pro rata share of all enrichment services received by the United States commercial nuclear power industry from the United States government through October 1992. Each year, the DOE will adjust the annual assessment using the Consumer Price Index. The Energy Policy Act provides that the assessments are to be treated as reasonable and necessary current costs of fuel, which costs shall be fully recoverable in rates in all jurisdictions. The System's total share of the estimated assessment was approximately $62.4 million. Management believes that the DOE assessments against CL&P, WMECO, PSNH and NAEC will be recoverable in future rates. Accordingly, each of these companies has recognized these costs as a regulatory asset, with a corresponding obligation on its balance sheet.

On June 22, 1995, the United States Court of Federal Claims held that, as applied to YAEC, the Uranium Enrichment Decontamination and Decommissioning Fund is an unlawful add-on to the bargained-for contract price for enriched uranium. As a result, the federal government must refund the approximately $3.0 million that YAEC has paid into the fund since its inception. NU is evaluating the applicability of this decision to the $21 million that the System companies have already paid into the fund, and whether this alters the System companies' obligation to pay such special assessments in the future. The decision as to YAEC has been appealed by the federal government.

Nuclear fuel costs associated with nuclear plant operations include amounts for disposal of nuclear waste. The System companies include in their nuclear fuel expense spent fuel disposal costs accepted by the DPUC, NHPUC and DPU in rate case or fuel adjustment decisions. Spent fuel disposal costs are also reflected in FERC-approved wholesale charges. Such provisions include amortization and recovery in rates of previously unrecovered disposal costs of accumulated spent nuclear fuel.

HIGH-LEVEL RADIOACTIVE WASTE

The Nuclear Waste Policy Act of 1982 (NWPA) provides that the federal government is responsible for the permanent disposal of spent nuclear reactor fuel and high-level waste. As required by the NWPA, electric utilities generating spent nuclear fuel and high-level waste are obligated to pay fees into a fund which would be used to cover the cost of siting, constructing, developing and operating a permanent disposal facility for this waste. The System companies have been paying for such services for fuel burned starting in April 1983 on a quarterly basis since July 1983. The DPUC, NHPUC and DPU permit the fee to be recovered through rates.

In return for payment of the fees prescribed by the NWPA, the federal government is to take title to and dispose of the utilities' high-level wastes and spent nuclear fuel. The NWPA provides that a disposal facility be operational and for the DOE to accept nuclear waste for permanent disposal in 1998. On April 28, 1995, DOE issued an interpretative release stating that it does not have an unconditional statutory or contractual obligation to accept spent fuel beginning January 1, 1998.

On June 23, 1995, the DPUC and the New Hampshire Office of Consumer Advocate joined the Connecticut, New Hampshire and Massachusetts Attorneys General and a number of states in a lawsuit filed in federal court against the DOE, seeking a declaratory judgment that the DOE has a statutory obligation to take high-level nuclear waste from utilities in 1998 and to establish judicially administered milestones to enforce that obligation. On October 4, 1995, NUSCO, NAESCO and CYAPC joined a companion lawsuit filed by a number of utilities seeking similar relief. The cases were consolidated by the federal court of appeals. Oral argument was held on January 17, 1996, and the matter is still pending. Nuclear utilities and state regulators are presently considering additional steps that they might take to ensure that the DOE is able to meet its obligations with regard to nuclear waste disposal as soon as possible.

Until the federal government begins accepting nuclear waste for disposal, operating nuclear generating plants will need to retain high-level waste and spent fuel on-site or make some other provisions for their storage. With the addition of new storage racks, storage facilities for

Millstone 3 and CY are expected to be adequate for the projected life of the units. The storage facilities for Millstone 1 and 2 are expected to be adequate (maintaining the capacity to accommodate a full-core discharge from the reactor) until 2001. Fuel consolidation, which has been licensed for Millstone 2, could provide adequate storage capability for the projected lives of Millstone 1 and 2. In addition, other licensed technologies, such as dry storage casks or on-site transfers, are being considered to accommodate spent fuel storage requirements. With the current installation of new racks in its existing spent fuel pool, Seabrook is expected to have spent fuel storage capacity until at least 2010.

In 1995, MYAPC began replacing the fuel racks in the spent fuel pool at MY to provide for additional storage capacity. MYAPC believes that the replacement of the fuel racks will provide adequate storage capacity through MY's current licensed operating life. The storage capacity of the spent fuel pool at VY is expected to be reached in 2005, and the available capacity of the pool is expected to be able to accommodate full-core removal until 2001.

Because the Yankee Rowe plant was permanently shut down in February 1992, YAEC is considering the construction of a temporary facility to store the spent nuclear fuel produced by the Yankee Rowe plant over its operating lifetime until that fuel is removed by the DOE. See "Electric Operations-Nuclear Generation-Decommissioning" for further information on the closing and decommissioning of Yankee Rowe, including a recent order issued by the NRC halting decommissioning activities at Yankee Rowe.

LOW-LEVEL RADIOACTIVE WASTE

In April 1995, the Northwest interstate compact passed a resolution and order broadening the types of low-level radioactive waste (LLRW) acceptable for disposal at the privately operated Envirocare facility in Utah. This policy change made a significant portion of utility LLRW acceptable for disposal at Envirocare. In July 1995, the state of South Carolina reopened the Barnwell LLRW disposal site to the nation (except for North Carolina).

These events enabled Seabrook to begin shipping its first LLRW ever and, for the first time since 1992, gave Millstone Station and CY a choice of disposal sites for certain categories of LLRW. By the end of November 1995, the System had contracts with both Barnwell and Envirocare for operational LLRW disposal. The vast majority of LLRW in storage from July 1994 through June 1995 at Millstone station and CY, and in storage since startup at the Seabrook plant, was shipped to either Barnwell or Envirocare by the end of 1995. The System incurred approximately $8 million in off-site LLRW disposal costs in 1995 for the five nuclear units it operates.

Because access to LLRW disposal may be lost at any time, the System has plans that will allow for on-site storage of LLRW for at least five years in the event that disposal is interrupted. Both Connecticut and New Hampshire are also pursuing other options for out-of-state disposal of LLRW.

MY had stored all its LLRW on-site since January 1, 1993, when it lost access to off-site disposal facilities. Most of this stored waste has been shipped to Barnwell since Maine regained access to the site in mid-1995.

The plant has the capability to store a volume of LLRW equivalent to at least five years generation, in the event that off-site disposal access is lost.

VY has stored all its LLRW on-site since July 1994. The plant also has the capacity to store a volume of LLRW equivalent to at least five years generation, in the event that off-site disposal access is lost. With access to Barnwell in mid-1995, VY has elected to continue storing most of its LLRW on-site in anticipation of lower future disposal costs at the yet-to-be constructed Texas LLRW disposal site.

Both Maine and Vermont are in the process of implementing an agreement with Texas to provide access to a LLRW disposal facility that is to be developed in that state. All three states plan to form a LLRW compact that is currently awaiting approval by Congress.

DECOMMISSIONING

Based upon the System's most recent comprehensive site-specific updates of the decommissioning costs for each of the three Millstone units and for Seabrook, the recommended decommissioning method continues to be immediate and complete dismantlement of those units at their retirement. The table below sets forth the estimated Millstone and Seabrook decommissioning costs for the System companies. The estimates are based on the latest site studies, escalated to December 31, 1995 dollars.

	CL&P	PSNH	WMECO (Millions)	NAEC	System
Millstone 1	$300.3	$ -	$ 70.4	$ -	$ 370.7
Millstone 2	265.8	-	62.3	-	328.1
Millstone 3	232.0	12.5	53.7	-	298.2
Seabrook 1	17.2	-	-	152.5	169.7
Total	$815.3	$12.5	$186.4	$152.5	$1166.7

As of December 31, 1995, the balances (at market) in certain external decommissioning trust funds, as discussed more fully below, were as follows:

	CL&P	PSNH	WMECO (Millions)	NAEC	System
Millstone 1	$113.2	$ -	$ 33.8	$ -	$147.0
Millstone 2	73.2	-	22.8	-	96.0
Millstone 3	49.9	2.4	13.3	-	65.6
Seabrook 1	1.7	-	-	15.3	17.0
Total	$238.0	$ 2.4	$ 69.9	$15.3	$325.6

Pursuant to Connecticut law, CL&P has periodically filed plans with the DPUC for financing the decommissioning of the three Millstone units. In 1986, the DPUC approved the establishment of separate external trusts for the currently tax-deductible portions of decommissioning expense accruals for Millstone 1 and 2 and for all expense accruals for Millstone 3. In its 1993 CL&P multiyear rate case decision, the DPUC allowed CL&P's full decommissioning estimate for the three Millstone units to be collected from customers. This estimate includes an approximate 16 percent contingency factor for the decommissioning cost of each unit. The estimated aggregate cost of decommissioning the System's ownership share in the Millstone units is approximately $997 million in December 1995 dollars.

WMECO has established independent trusts to hold all decommissioning expense collections from customers. In its 1990 WMECO multiyear rate case decision, the DPU allowed WMECO's decommissioning estimate for the three Millstone units ($840 million in December 1990 dollars) to be collected from customers. Due to the settlement in the 1992 WMECO rate case, the aggregate decommissioning estimate for the three Millstone units remains unchanged.

New Hampshire enacted a law in 1981 requiring the creation of a state-managed fund to finance decommissioning of any units in that state. The New Hampshire Decommissioning Fund Commission (NHDFC) approved a revised decommissioning estimate in June 1995. On the basis of this revised estimate, the total decommissioning cost for the System's ownership share of Seabrook is $169.7 million in December 1995 dollars. NAEC's costs for decommissioning are billed by it to PSNH and recovered by PSNH under the Rate Agreement. Under the Rate Agreement, PSNH is entitled to a base rate increase to recover increased decommissioning costs. See "Rates—New Hampshire Retail Rates-General" for further information on the Rate Agreement.

The decommissioning cost estimates for the System nuclear units are reviewed and updated regularly to reflect inflation and changes in decommissioning requirements and technology. Changes in requirements or technology, or adoption of a decommissioning method other than immediate dismantlement, could change these estimates. CL&P, PSNH and WMECO attempt to recover sufficient amounts through their allowed rates to cover their expected decommissioning costs. Only the portion of currently estimated total decommissioning costs that has been accepted by regulatory agencies is reflected in rates of the System companies. Based on present estimates, and assuming its nuclear units operate to the end of their respective license periods, the System expects that the decommissioning trusts funds will be substantially funded when those expenditures have to be made.

CYAPC, YAEC, VYNPC and MYAPC are all collecting revenues for decommissioning from their power purchasers. The table below sets forth the estimated decommissioning costs of the Yankee units for the System companies. The estimates are based on the latest site studies, escalated to December 31, 1995 dollars. For information on the equity ownership of the System companies in each of the Yankee units, see "Electric Operations-Nuclear Generation-General."

	CL&P	PSNH	WMECO	System
		(Millions)		
VY	$ 33.0	$ 13.9	$ 8.7	$ 55.6
Yankee Rowe*	65.9	18.8	18.8	103.5
CY	133.0	19.3	36.6	188.9
MY	42.4	17.7	10.6	70.7
Total	$274.3	$ 69.7	$ 74.7	$418.7

* The costs shown include all remaining decommissioning costs and other closing costs associated with the early retirement of Yankee Rowe as of December 31, 1995.

As of December 31, 1995, the balances (at market) in the external decommissioning trust funds for the Yankee units were as follows:

	CL&P	PSNH	WMECO	System
		(Millions)		
VY	$ 13.4	$ 5.7	$ 3.5	$ 22.6
Yankee Rowe	29.0	8.3	8.3	45.6
CY	61.6	8.9	17.0	87.5
MY	17.1	7.1	4.2	28.4
Total	$121.1	$30.0	$33.0	$184.1

YAEC has begun decommissioning its nuclear facility. However, on October 12, 1995, the NRC issued an order halting major dismantlement or decommissioning activities at Yankee Rowe until after completion of an adjudicatory hearing process. The NRC's action was taken in response to a recent federal appeals court decision finding that the NRC should have offered a hearing opportunity prior to authorizing Yankee Rowe's component removal program in 1993. On January 16, 1996, the NRC issued a decision requiring that the proceeding, including hearings if necessary, be completed by mid-July 1996. Based on a pre-hearing conference held on February 21, 1996, YAEC expects that the NRC will reapprove the Yankee Rowe decommissioning plan.

On December 29, 1995, FERC approved a revised decommissioning estimate for Yankee Rowe, which assumed prompt resumption of major decommissioning activities. Based on the revised decommissioning estimate, the total remaining decommissioning cost for the System's ownership share of Yankee Rowe is approximately $103.5 million in December 1995 dollars.

CYAPC accrues decommissioning costs on the basis of immediate dismantlement at retirement. In May 1993, FERC approved a settlement agreement in a CYAPC rate proceeding allowing a revised decommissioning estimate of $294.2 million (in July 1992 dollars) to be recovered in rates beginning on June 1, 1993. This amount will increase by a stated amount each year for inflation. The most current estimated decommissioning cost of the System's ownership share is approximately $188.9 million in year-end 1995 dollars.

MYAPC estimates the cost of the System's ownership share of decommissioning MY at $70.7 million in December 31, 1995 dollars based on a study completed in July 1993. VYNPC estimates the cost of the System's ownership share of decommissioning VY at $55.6 million in December 31, 1995 dollars based on a study completed in March 1994.

NONUTILITY BUSINESSES

PRIVATE POWER DEVELOPMENT

The System participates as a developer and investor in domestic and international private power projects through its subsidiary, Charter Oak. Management currently does not permit Charter Oak to invest in facilities which are located within the System service territory or sell electric output to any of the System electric utility companies. Charter Oak is investing primarily in projects outside of the United States.

SURFACE WATER QUALITY REQUIREMENTS

The federal Clean Water Act (CWA) requires every "point source" discharger of pollutants into navigable waters to obtain a National Pollutant Discharge Elimination System (NPDES) permit from the United States Environmental Protection Agency (EPA) or state environmental agency specifying the allowable quantity and characteristics of its effluent. System facilities have all required NPDES permits in effect. Compliance with NPDES and state water discharge permits has necessitated substantial expenditures and may require further expenditures because of additional requirements that could be imposed in the future.

On October 13, 1995, the Connecticut Department of Environmental Protection (CDEP) issued a consent order to CL&P and the Long Island Lighting Company (LILCO) requiring those companies to address leaks from the Long Island cable, which is jointly owned by CL&P and LILCO. The order requires CL&P and LILCO to study and propose alternatives for prevention, detection and mitigation of oil leaks and to evaluate the ecological effects of leaks on the environment. Alternatives to be studied include replacement of the cable and the dielectric fluid currently used in the cable. The System will incur additional costs to meet the requirements of the order and to meet any subsequent CDEP requirements resulting from the studies under the consent order, which costs cannot be estimated at this time. Management also cannot determine at this time whether long-term future operation of the cable will remain cost effective subsequent to any additional CDEP requirements.

In early February 1996, the CDEP notified CL&P and LILCO that it desired to amend the consent order to cover transformer oil that was inadvertently introduced into the cable by LILCO at its pumping station on Long Island. LILCO is in the process of removing the transformer oil from the cable and has instituted safeguards to prevent it from happening again. The System does not believe that any of the transformer oil reached the part of the cable in Connecticut.

The United States Attorney's Office in New Haven, Connecticut has commenced an investigation and has issued subpoenas to CL&P, NU, NUSCO, CONVEX and LILCO seeking documents relating to operation and maintenance of and recent leaks from the Long Island cable. Since the investigation is in its preliminary stages and the government has not revealed the scope of its investigation, management cannot evaluate the likelihood of a criminal proceeding being initiated at this time. However, management is aware of nothing that would suggest that any System company, officer or employee has engaged in conduct that would warrant such a proceeding.

The CWA requires EPA and state permitting authorities to approve the cooling water intake structure design and thermal discharge of steam-electric generating plants. All System steam-electric plants have received these approvals. In the renewed NPDES discharge permit for the three Millstone nuclear units, issued in 1992, CDEP included a condition requiring a feasibility study of various structural or operational modifications of the cooling water intake system to reduce the entrainment of winter flounder larvae. The report, submitted in 1993, concluded that the mitigation alternatives examined were not technically feasible or cost effective. The CDEP found that the current cooling water intake represents the "best available technology" for minimizing adverse impacts, but required NNECO to schedule refueling outages, when possible, to coincide with high larval winter flounder abundance at the intakes and to report the results of such efforts. The NPDES permit further states that additional evidence may result in the agency imposing more stringent requirements.

Merrimack Station's NPDES permit requires site work to isolate adjacent wetlands from the station's waste water system. Plans have been approved by the New Hampshire Department of Environmental Services (NHDES), and PSNH is now preparing a permit application to begin construction.

The Merrimack permit also requires PSNH to perform further biological studies because significant numbers of migratory fish are being restored to lower reaches of the Merrimack River. These studies are in progress and initial results will be reported in 1996. Preliminary findings from these studies indicate that Merrimack Station's once-through cooling system does not interfere with the establishment of a balanced aquatic community. However, if NHDES determines there is interference, PSNH could be required to construct a partially enclosed cooling water system for Merrimack Station. The amount of capital expenditures relating to the foregoing cannot be determined at this time. However, if such expenditures were required, they would likely be substantial and a reduction of Merrimack Station's net generation capability could result.

The ultimate cost impact of the CWA and state water quality regulations on the System cannot be estimated because of uncertainties such as the impact of changes to the effluent guidelines or water quality standards. Additional modifications, in some cases extensive and involving substantial cost, may ultimately be required for some or all of the System's generating facilities.

In response to several major oil spills in recent years, Congress passed the Oil Pollution Act of 1990 (OPA 90). OPA 90 sets out the requirements for facility response plans and periodic inspections of spill response equipment at facilities that can cause substantial harm to the environment by discharging oil or hazardous substances into the navigable waters of the United States and onto adjoining shorelines. Pursuant to OPA 90, EPA has authority to regulate nontransportation-related fixed onshore facilities and the United States Coast Guard (Coast Guard) has the authority to regulate transportation-related onshore facilities. Response plans were filed for all System facilities believed to be subject to this requirement. The Coast Guard has completed its final review process and issued its approval of these plans. The EPA has issued its approval of all facility plans except PSNH's Schiller Station, where the EPA has authorized continued operation pending its final plan approval.

OPA 90 includes limits on the liability that may be imposed on persons deemed responsible for release of oil. The limits do not apply to oil spills caused by negligence or violation of laws or regulations. OPA 90 also does not preempt state laws regarding liability for oil spills. In general, the laws of the states in which the System owns facilities and through which the System transports oil could be interpreted to impose strict liability for the cost of remediating releases of oil and for damages caused by releases. The System and its principal oil transporter currently carry a total of $900 million in insurance coverage for oil spills.

AIR QUALITY REQUIREMENTS

The Clean Air Act Amendments of 1990 (CAAA) made extensive revisions and additions to the federal Clean Air Act and imposed many stringent new requirements on air emissions sources. The CAAA contains provisions that further regulate emissions of sulfur dioxide (SO2) and nitrogen oxide (NOX) for the purpose of controlling acid rain and ground level ozone. In addition, the CAAA addresses the control of toxic air pollutants. Installation of continuous emissions monitors (CEMs) and expanded permitting provisions are also included.

Existing and future federal and state air quality regulations could hinder or possibly preclude the construction of new, or the modification of existing, fossil units in the System's service area and could raise the capital and operating cost of existing units. The ultimate cost impact of these requirements on the System cannot be estimated because of uncertainties about how EPA and the states will implement various requirements of the CAAA.

Nitrogen Oxide. Title I of the CAAA identifies NOX emissions as a precursor of ambient ozone. The Northeastern region of the United States, including Connecticut, Massachusetts and New Hampshire, currently exceeds the ambient air quality standard for ozone. Pursuant to the CAAA, states exceeding the ozone standard must implement plans to address ozone nonattainment. All three states have issued final regulations to implement Phase I reduction requirements, and the System has met these requirements. Compliance with Phase I requirements has cost the System a total of approximately $41 million: $10 million for CL&P, $27 million for PSNH, $1 million for WMECO and $3 million for HWP. Compliance has been achieved using a combination of currently available technology, combustion efficiency improvements and emissions trading. Compliance costs for Phase II, effective in 1999, are expected to result in an additional cost of $10 to $15 million.

In December 1993, PSNH reached a revised agreement regarding NOX emissions with various environmental groups and the New Hampshire Business and Industrial Association (NHBIA). The agreement provides for aggressive unit-specific NOX emission rate limits for PSNH's generating facilities, effective May 31, 1995. The agreement relieves PSNH of a prior commitment to retire or repower Merrimack Unit 2 by May 15, 1999. More stringent emission rate limits equivalent to the range of 0.1 to 0.4 pounds of NOX per million Btu, however, are required for the unit by that date. In May 1994, NHDES promulgated the New Hampshire NOX reduction rule in accordance with the terms of the NHBIA Agreement. PSNH has complied with the requirements of this rule by installing controls on the units. The additional requirements for Merrimack Unit 2 for 1999 may be attained through increased catalytic reduction of NOX at an additional estimated cost of $5 to $7 million.

Sulfur Dioxide. The CAAA mandates reductions in SO2 emissions to control acid rain. These reductions are to occur in two phases. First, certain high SO2 emitting plants were required to reduce their emissions beginning January 1, 1995. All Phase I units will be allocated SO2 allowances for the period 1995-1999. These allowances are freely tradable. One allowance entitles a source to emit one ton of SO2 in a year. No unit may emit more SO2 in a particular year than the amount for which it has allowances. The only System units subject to the Phase I reduction requirements are PSNH's Merrimack Units 1 and 2. Additionally, Newington Station in New Hampshire and Mt. Tom Station in Massachusetts are conditional Phase I units. This means that the System can decide to include these plants as Phase I units during any year and obtain allowances for that year. The System has included these plants as Phase I units for 1995.

On January 1, 2000, the start of Phase II, a nationwide cap of 8.9 million tons per year of utility SO2 emissions will be imposed and existing units will be granted allowances to emit SO2. Most of the System companies' allocated allowances will substantially exceed its expected SO2 emissions for 2000 and subsequent years, except for PSNH, which expects to purchase additional SO2 allowances from either affiliated or nonaffilated companies.

New Hampshire and Massachusetts have each instituted acid rain control laws that limit SO2 emissions. The System is meeting the new SO2 limitations by using natural gas and lower sulfur coal in its plants. Under the existing fuel adjustment clauses in Connecticut, New Hampshire and Massachusetts, the System should be able to recover the additional fuel costs of compliance with the CAAA and state laws from its customers. For more information regarding a prudence hearing in New Hampshire on costs associated with PSNH's capital expenditures to comply with Phase I reduction requirements, see "Rates-New Hampshire Retail Rates-FPPAC."

Management does not believe that the acid rain provisions of the CAAA will have a significant impact on the System's overall costs or rates due to the very strict limits on SO2 emissions already imposed by Connecticut, New Hampshire and Massachusetts. In addition, management believes that Title IV of the CAAA (acid rain) requirements for NOX limitations will not have a significant impact on System costs due to the more stringent NOX limitations resulting from Title I of the CAAA discussed above.

EPA, Connecticut, New Hampshire and Massachusetts regulations also include other air quality standards, emission standards and monitoring and testing and reporting requirements that apply to the System's generating stations. They require that new or modified fossil fuel-fired electric generating units operate within stringent emission limits. The System could incur additional costs to meet these requirements, which costs cannot be estimated at this time.

Air Toxics. Title III of the CAAA directed EPA to study air toxics and mercury emissions from fossil fired steam electric generation units to determine if they should be regulated. EPA exempted these plants from the hazardous air pollutant program pending completion of the studies, expected this year. Should EPA determine that such generating plants' emissions must be controlled to the same extent as emissions from other sources under Title III, the System could be required to make substantial capital expenditures to upgrade or replace pollution control equipment, but the amount of these expenditures cannot be readily estimated.

TOXIC SUBSTANCES AND HAZARDOUS WASTE REGULATIONS

PCBs. Under the federal Toxic Substances Control Act of 1976 (TSCA), EPA has issued regulations that control the use and disposal of polychlorinated biphenyls (PCBs). PCBs had been widely used as insulating fluids in many electric utility transformers and capacitors before TSCA prohibited any further manufacture of such PCB equipment. System companies have taken numerous steps to comply with these regulations and have incurred increased costs for disposal of used fluids and equipment that are subject to the regulations.

In general, the System sends fluids with concentrations of PCBs equal to or higher than 500 ppm but lower than 8,500 ppm to an unaffiliated company to dispose of using a chemical treatment process. Electrical capacitors that contain PCB fluid are sent off-site to dispose of through burning in high temperature incinerators approved by EPA. The System disposes of solid wastes containing PCBs in secure chemical waste landfills.

Asbestos. Federal, Connecticut, New Hampshire and Massachusetts asbestos regulations have required the System to expend significant sums on removal of asbestos, including measures to protect the health of workers and the general public and to properly dispose of asbestos wastes. Asbestos costs for the System are expected to be approximately $2 million in 1996. These costs are generally included in capital budgets.

RCRA. Under the federal Resource Conservation and Recovery Act of 1976, as amended (RCRA), the generation, transportation, treatment, storage and disposal of hazardous wastes are subject to EPA regulations. Connecticut, New Hampshire and Massachusetts have adopted state regulations that parallel RCRA regulations but in some cases are more stringent. The procedures by which System companies handle, store, treat and dispose of hazardous wastes are regularly revised, where necessary, to comply with these regulations.

CL&P is expecting that EPA and CDEP will approve clean closure for CL&P's Montville and Middletown Stations' former surface impoundments. For the Norwalk Harbor and Devon sites, CL&P has applied for post-closure permits and is awaiting approval from EPA and CDEP. The System estimates that it will incur approximately $2.1 million in total costs for 30-year maintenance monitoring, and closure of the container storage areas and surface impoundments for these sites in the future, but the ultimate amount will depend on EPA's final disposition.

Hazardous Waste Liability. As many other industrial companies have done in the past, System companies have disposed of residues from operations by depositing or burying such materials on-site or disposing of them at off-site landfills or facilities. Typical materials disposed of include coal gasification waste, fuel oils, gasoline and other hazardous materials that might contain PCBs. It has since been determined that deposited or buried wastes, under certain circumstances, could cause groundwater contamination or create other environmental risks. The System has recorded a liability for what it believes is, based upon currently available information, its estimated environmental remediation costs for waste disposal sites for which the System companies expect to bear legal liability, and continues to evaluate the environmental impact of its former disposal practices. Under federal and state law, government agencies and private parties can attempt to impose liability on System companies for such past disposal. As of December 31, 1995, the liability recorded by the System for its estimated environmental remediation costs for known sites needing remediation including those sites described below, exclusive of recoveries from insurance or third parties, was approximately $15 million. This amount represents the minimum reserve required by the Financial

Accounting Standards Board. These costs could be significantly higher if alternative remedies become necessary.

Under the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, commonly known as Superfund, EPA has the authority to clean up or order cleanup of hazardous waste sites and to impose the cleanup costs on parties deemed responsible for the hazardous waste activities on the sites. Responsible parties include the current owner of a site, past owners of a site at the time of waste disposal, waste transporters and waste generators. It is EPA's position that all responsible parties are jointly and severally liable, so that any single responsible party can be required to pay the entire costs of cleaning up the site. As a practical matter, however, the costs of cleanup are usually allocated by agreement of the parties, or by the courts on an equitable basis among the parties deemed responsible, and several federal appellate court decisions have rejected EPA's position on strict joint and several liability. Superfund also contains provisions that require System companies to report releases of specified quantities of hazardous materials and require notification of known hazardous waste disposal sites. System companies are in compliance with these reporting and notification requirements.

The System currently is involved in two Superfund sites in Connecticut, one in Kentucky and two in New Hampshire. The level of study of each site and the information about the waste contributed to the site by the System and other parties differs from site to site. Where reliable information is available that permits the System to make a reasonable estimate of the expected total costs of remedial action and/or the System's likely share of remediation costs for a particular site, those cost estimates are provided below. All cost estimates were made in accordance with Financial Accounting Standards Board standards where remediation costs were probable and reasonably estimable. Any estimated costs disclosed for cleaning up the sites discussed below were determined without consideration of possible recoveries from third parties, including insurance recoveries. Where the System has not accrued a liability, the costs either were not material or there was insufficient information to accurately assess the System's exposure.

A coalition of major parties had previously joined "Northeast Utilities (Connecticut Light and Power)" (NU (CL&P))as defendants in connection with the Beacon Heights and Laurel Park Superfund sites in Connecticut. In 1993, the United States District Court for the District of Connecticut dismissed the coalitions' claims against NU (CL&P) and a number of other defendants. The coalitions, however, have appealed the district court's decision, which is currently pending.

EPA has issued a notice of potential liability to NNECO and CYAPC as potentially responsible parties (PRPs) at the Maxey Flats nuclear waste disposal site in Fleming County, Kentucky. The System had sent a substantial volume of LLRW from Millstone 1, Millstone 2 and CY to this site. PRPs that are members of the Maxey Flats PRP Steering Committee, including System companies, and several federal government agencies, including DOE and the Department of Defense as well as the Commonwealth of Kentucky have reached a tentative settlement with EPA embodied in a consent decree. On February 8, 1996, this consent decree was filed by the United States Department of Justice in a federal district court in Kentucky for approval. NUSCO, on behalf of NNECO and CYAPC, signed the consent decree in March 1995. The System has recorded a liability for future remediation costs for this site based on its best estimate of its share of ultimate remediation costs under the tentative agreement. The System's future liability at the site has been assessed at slightly over $1 million.

PSNH has committed approximately $280,000 as its share to clean up one municipal landfill Superfund site in Dover, New Hampshire and has been assessed a de minimus share at another such site in North Hampton, New Hampshire. Some additional costs may be incurred at these sites, but they are not expected to be significant.

As discussed below, in addition to the remediation efforts for the above-mentioned Superfund sites, the System has been named as a PRP and is monitoring developments in connection with several state environmental actions.

In 1987, CDEP published a list of 567 hazardous waste disposal sites in Connecticut. The System owns two sites on this list, which are also listed on the EPA's list of hazardous waste sites. The System has spent approximately $700,000, as of December 31, 1995, completing investigations at these sites. Both sites were formerly used by CL&P predecessor companies for the manufacture of coal gas (also known as town gas sites) from the late 1800s to the 1950s. This process resulted in the production of coal tar and creosote residues and other byproducts, which, when not sold for other industrial or commercial uses, were frequently deposited on or near the production facilities. Site investigations are being carried out to gain an understanding of the environmental and health risks of these sites. Assessments of the need for site remediation is ongoing. The level of future cleanup will be established in cooperation with CDEP, which has recently issued cleanup standards for soil and groundwater.

One of the sites is a 25.8-acre site located in the south end of Stamford, Connecticut. Site investigations have located coal tar deposits covering approximately 5.5 acres and having a volume of approximately 45,000 cubic yards. A final risk assessment report for the site was completed in January 1994. Several remedial options have been evaluated to clean up the site, if necessary. The estimated costs of remediation and institutional controls range from $5 to $13 million.

The second site is a 3.5-acre former coal gasification facility that currently serves as an active substation in Rockville, Connecticut. Site investigations have located creosote and other polyaromatic hydrocarbon contaminants which may require remediation. Several options are being evaluated to remediate the site if necessary. To further evaluate the health risks at the site, additional studies are being planned in coordination with the CDEP during 1996.

As part of the 1989 divestiture of CL&P's gas business, site investigations were performed for properties that were transferred to Yankee Gas Services Company (Yankee Gas). CL&P agreed to accept liability for any required cleanup for the three sites it retained. These three sites include Stamford and Rockville (discussed above) and Torrington, Connecticut. At the Torrington site, investigations have been completed and the cost of any remediation, if necessary, is not expected to be material. CL&P and Yankee Gas also share a site in Winsted, Connecticut and any liability for required cleanup there. CL&P and Yankee Gas will share the costs of cleanup of sites formerly used in CL&P's gas business but not currently owned by either of them.

PSNH contacted NHDES in December 1993 concerning possible coal tar contamination in Laconia, New Hampshire in Lake Opechee and the Winnipesaukee River near an area where PSNH and a second PRP formerly owned and operated a coal gasification plant from the late 1800's to the 1950's. PSNH completed a preliminary site investigation in December 1994. Results indicate that off-site coal tar/creosote contamination is present in the adjacent water body. A comprehensive site investigation is planned for 1996. The cost of remediation, if necessary, at this site is estimated at $5 to 8 million. PSNH has entered into an interim cost sharing agreement with the other PRP wherein the other PRP will bear 25 percent of this cost. A second coal gasification facility formerly owned and operated by a predecessor company to PSNH is located in Keene, New Hampshire. The NHDES has been notified of the presence of coal tar contamination and further site investigations are planned in 1996. Additional New Hampshire sites include several former manufactured gasification facilities, an inactive ash landfill located at Dover Point and a municipal landfill in Peterborough. Historic reviews of these sites are ongoing. PSNH's liability at these sites cannot be estimated at this time.

In Massachusetts, System companies have been designated by the Massachusetts Department of Environmental Protection (MDEP) as PRPs for twelve sites under MDEP's hazardous waste and spill remediation program. At two sites, the System may incur remediation costs that may be material to HWP depending on the remediation requirements. At one site, HWP has been identified by MDEP as one of three PRPs in a coal tar site in Holyoke, Massachusetts. HWP owned and operated the Holyoke Gas Works from 1859 to 1902. The site is located on the east side of Holyoke, adjacent to the Connecticut River and immediately downstream of HWP's Hadley Falls Station. MDEP has designated both the land and river deposit areas as priority waste disposal sites. Due to the presence of tar patches in the vicinity of the spawning habitat of the shortnose sturgeon (SNS)—an endangered species—the National Oceanographic and Atmospheric Administration (NOAA) and National Marine Fisheries Service have taken an active role in overseeing site activities. Both MDEP and NOAA have indicated they may require the removal of tar deposits from the vicinity of the SNS spawning habitat. To date, HWP has spent approximately $405,000 for river studies and construction costs for an oil containment boom to prevent leaching hydrocarbons from entering the Hadley Falls tailrace and the Connecticut River. The total estimated costs for remediation of this site range from $2 to $3 million. The second site is a former manufactured gas plant facility in Easthampton, Massachusetts, owned by WMECO. The site is currently undergoing investigations both on-site and off-site to identify the extent of coal tar deposits.

In the past, the System has received other claims from government agencies and third parties for the cost of remediating sites not currently owned by the System but affected by past System disposal activities and may receive more such claims in the future. The System expects that the costs of resolving claims for remediating sites about which it has been notified will not be material, but cannot estimate the costs with respect to sites about which it has not been notified. If the System, regulatory agencies or courts determine that remedial actions must be taken in relation to past disposal practices on property owned or used for disposal by the System in the past, the System could incur substantial costs.

ELECTRIC AND MAGNETIC FIELDS

In recent years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Most researchers, as well as scientific review panels considering all significant EMF epidemiological and laboratory research to date, agree that current information remains inconclusive, inconsistent and insufficient for risk assessment of EMF exposures. Based on this information management does not believe that a causal relationship has been established or that significant capital expenditures are appropriate to minimize unsubstantiated risks. NU is closely monitoring research and government policy developments.

The System supports further research into the subject and is participating in the funding of the National EMF Research and Public Information Dissemination Program and other industry-sponsored studies. If further investigation were to demonstrate that the present electricity delivery system is contributing to increased risk of cancer or other health problems, the industry could be faced with the difficult problem of delivering reliable electric service in a cost-effective manner while managing EMF exposures. In addition, if the courts were to conclude that individuals have been harmed and that utilities are liable for damages, the potential monetary exposure for all utilities, including the System companies, could be enormous. Without definitive scientific evidence of a causal relationship between EMF and health effects, and without reliable information about the kinds of changes in utilities' transmission and distribution systems that might be needed to address the problem, if one is found, no estimates of the cost impacts of remedial actions and liability awards are available.

The Connecticut Interagency EMF Task Force (Task Force) provided a report to the state legislature in January 1995. The Task Force advocates a policy of "voluntary exposure control," which involves providing people with information to enable them to make individual decisions about EMF exposure. Neither the Task Force, nor any Connecticut state agency, has recommended changes to the existing electrical supply system. The Connecticut Siting Council (Siting Council) previously adopted a set of EMF "best management practices," which are now considered in the justification, siting and design of new transmission lines and substations. The Siting Council also opened a generic docket in 1994 to conduct a comparative life-cycle cost analysis of overhead and underground transmission lines, which was mandated by Connecticut PA-176. This act was adopted by the General Assembly in part due to public EMF concerns. The Siting Council hired consultants in 1995 to assist with this analysis. A decision is expected in 1996.

EMF has become increasingly important as a factor in facility siting decisions in many states. Several bills involving EMF were introduced in Massachusetts in 1995, with no action taken. These bills were similar to ones introduced in previous years, on which no action was taken. WMECO supported one of the bills, which would have authorized a special commission to investigate health effects, if any, of EMF, and conduct EMF measurements in schools and daycare centers near transmission lines. The Connecticut General Assembly likewise took no action on a bill introduced in 1995 concerning electromagnetic sources near schools.

CL&P has been the focus of media reports charging that EMF associated with a CL&P substation and related distribution lines in Guilford, Connecticut, are linked with various cancers and other illnesses in several nearby residents. See "Item 3. Legal Proceedings," for information about two suits brought by plaintiffs who now live or formerly lived near that substation.

FERC HYDRO PROJECT LICENSING

Federal Power Act licenses may be issued for hydroelectric projects for terms of up to 50 years as determined by FERC. Upon the expiration of a license, any hydroelectric project so licensed is subject to reissuance by FERC to the existing licensee or to others upon payment to the licensee of the lesser of fair value or the net investment in the project plus severance damages less certain amounts earned by the licensee in excess of a reasonable rate of return.

The System companies hold FERC licenses for 19 hydroelectric projects aggregating approximately 1,142 MW of capacity, located in Connecticut, Massachusetts and New Hampshire. Four of the System licenses expired on December 31, 1993 (WMECO's Gardners Falls project and PSNH's Ayers Island, Smith and Gorham projects). On August 1, 1994, FERC issued new 30-year licenses to PSNH for the continued operation of the Smith and Gorham projects. Although rehearing requests on these new licenses are pending with FERC, it is anticipated that it will be economic for PSNH to continue operation of these projects. FERC has issued annual licenses allowing the Gardners Falls and Ayers Island projects to continue operations pending completion of the relicensing process. It is not known whether FERC will require any substantial changes in the operation or design of these two projects if and when it issues new licenses.

The license for HWP's Holyoke Project expires in late 1999. The relicensing process for this project began in 1994. On November 29, 1995, the Holyoke Gas and Electric Department initiated the process of applying to FERC for the license on the Holyoke Project. Absent significant differences in competing license applications, the Federal Power Act gives a preference to an existing licensee for the new license. Applications must be filed with FERC by August 1997.

CL&P's FERC licenses for operation of the Falls Village and Housatonic Hydro Projects expire in 2001. The relicensing process for these projects will begin later in 1996.

FERC has issued a notice indicating that it has authority to order project licensees to decommission projects that are no longer economic to operate. FERC has not required any such project decommissioning to date; the potential costs of decommissioning a project, however, could be substantial. It is likely that this FERC decision will be appealed at an appropriate time.

EMPLOYEES

As of December 31, 1995, the System companies had 9,051 full and part-time employees on their payrolls, of which 2,285 were employed by CL&P, 1,339 by PSNH, 533 by WMECO, 101 by HWP, 1,333 by NNECO, 2,589 by NUSCO and 871 by NAESCO. NU, NAEC and Charter Oak have no employees.

In 1995 and early 1996, the System implemented a program to reduce the nuclear organization's total workforce by approximately 220 employees, which included both early retirements and involuntary terminations. The pretax cost of the program was approximately $8.7 million.

Approximately 2,275 employees of CL&P, PSNH, WMECO, NAESCO and HWP are covered by nine union agreements, which expire between May 31, 1996 and October 1, 1998. Approximately 370 union employees of WMECO and HWP returned to work on September 1, 1995, ending a strike that began on May 25, 1995.

ITEM 2. Properties

The physical properties of the System are owned or leased by subsidiaries of NU. CL&P's principal plants and other properties are located either on land which is owned in fee or on land, as to which CL&P owns perpetual occupancy rights adequate to exclude all parties except possibly state and federal governments, which has been reclaimed and filled pursuant to permits issued by the United States Army Corps of Engineers. The principal properties of PSNH are held by it in fee. In addition, PSNH leases space in an office building under a 30-year lease expiring in 2002. WMECO's principal plants and a major portion of its other properties are owned in fee, although one hydroelectric plant is leased. NAEC owns a 35.98 percent interest in Seabrook 1 and approximately 719 acres of exclusion area land located around the unit. In addition, CL&P, PSNH, and WMECO have certain substation equipment, data processing equipment, nuclear fuel, nuclear control room simulators, vehicles, and office space that are leased. With few exceptions, the System companies' lines are located on or under streets or highways, or on properties either owned or leased, or in which the company has appropriate rights, easements, or permits from the owners.

CL&P's properties are subject to the lien of its first mortgage indenture. PSNH's properties are subject to the lien of its first mortgage indenture. In addition, any PSNH outstanding revolving credit agreement borrowings are secured by a second lien, junior to the lien of the first mortgage indenture, on PSNH's property located in New Hampshire. WMECO's properties are subject to the lien of its first mortgage indenture. NAEC's First Mortgage Bonds are secured by a lien on the Seabrook 1 interest described above, and all rights of NAEC under the Seabrook Power Contract. In addition, CL&P's and WMECO's interests in Millstone 1 are subject to second liens for the benefit of lenders under agreements related to pollution control revenue bonds. Various of these properties are also subject to minor encumbrances which do not substantially impair the usefulness of the properties to the owning company.

The System companies' and NAEC's properties are well maintained and are in good operating condition.

Transmission and Distribution System

At December 31, 1995, the System companies owned 103 transmission and 427 distribution substations that had an aggregate transformer capacity of 25,000,646 kilovoltamperes (kVa) and 9,134,229 kVa, respectively; 3,057 circuit miles of overhead transmission lines ranging from 69 kilovolt (kV) to 345 kV, and 192 cable miles of underground transmission lines ranging from 69 kV to 138 kV; 32,593 pole miles of overhead and 1,912 conduit bank miles of underground distribution lines; and 391,562 line transformers in service with an aggregate capacity of 16,422,713 kVa.

Electric Generating Plants

As of December 31, 1995, the electric generating plants of the System companies and NAEC, and the System companies' entitlements in the generating plants of the three operating Yankee regional nuclear generating companies were as follows (See "Item 1. Business - Electric Operations, Nuclear Generation" for information on ownership and operating results for the year.):

Owner	Plant Name (Location)	Type	Year Installed	Claimed Capability* (kilowatts)
CL&P	Millstone (Waterford, CT)			
	Unit 1	Nuclear	1970	524,637
	Unit 2	Nuclear	1975	708,345
	Unit 3	Nuclear	1986	606,453
	Seabrook (Seabrook, NH)	Nuclear	1990	47,013
	CT Yankee (Haddam, CT)	Nuclear	1968	201,204
	ME Yankee (Wiscasset, ME)	Nuclear	1972	94,832
	VT Yankee (Vernon, VT)	Nuclear	1972	45,353
	Total Nuclear-Steam Plants	(7 units)		2,227,837
	Total Fossil-Steam Plants	(9 units)	1954-73	1,776,400
	Total Hydro-Conventional	(25 units)	1903-55	98,930
	Total Hydro-Pumped Storage	(7 units)	1928-73	905,150
	Total Internal Combustion	(15 units)	1966-86	390,450
	Total CL&P Generating Plant	(63 units)		5,398,767
PSNH	Millstone (Waterford, CT)			
	Unit 3	Nuclear	1986	32,624
	CT Yankee (Haddam, CT)	Nuclear	1968	29,160
	ME Yankee (Wiscasset, ME)	Nuclear	1972	39,514
	VT Yankee (Vernon, VT)	Nuclear	1972	19,068
	Total Nuclear-Steam Plants	(4 units)		120,366
	Total Fossil-Steam Plants	(7 units)	1952-78	1,004,065
	Total Hydro-Conventional	(20 units)	1917-83	67,510
	Total Internal Combustion	(5 units)	1968-70	108,450
	Total PSNH Generating Plant	(36 units)		1,300,391
WMECO	Millstone (Waterford, CT)			
	Unit 1	Nuclear	1970	123,063
	Unit 2	Nuclear	1975	166,155
	Unit 3	Nuclear	1986	140,216
	CT Yankee (Haddam, CT)	Nuclear	1968	55,404
	ME Yankee (Wiscasset, ME)	Nuclear	1972	23,708
	VT Yankee (Vernon, VT)	Nuclear	1972	11,948
	Total Nuclear-Steam Plants	(6 units)		520,494
	Total Fossil-Steam Plants	(1 unit)	1957	107,000
	Total Hydro-Conventional	(27 units)	1904-34	110,910**
	Total Hydro-Pumped Storage	(4 units)	1972-73	205,200
	Total Internal Combustion	(3 units)	1968-69	63,500
	Total WMECO Generating Plant	(41 units)		1,007,104

Owner	Plant Name (Location)	Type	Year Installed	Claimed Capability* (kilowatts)
NAEC	Seabrook (Seabrook, NH)	Nuclear	1990	416,672
HWP	Mt. Tom (Holyoke, MA)	Fossil-Steam	1960	147,000
	Total Hydro-Conventional	(15 units)	1905-83	43,560
	Total HWP Generating Plant	(16 units)		190,560
NU System	Millstone (Waterford, CT)			
	Unit 1	Nuclear	1970	647,700
	Unit 2	Nuclear	1975	874,500
	Unit 3	Nuclear	1986	779,293
	Seabrook (Seabrook, NH)	Nuclear	1990	463,685
	CT Yankee (Haddam, CT)	Nuclear	1968	285,768
	ME Yankee (Wiscasset, ME)	Nuclear	1972	158,054
	VT Yankee (Vernon, CT)	Nuclear	1972	76,369
	Total Nuclear-Steam Plants	(7 units)		3,285,369
	Total Fossil-Steam Plants	(18 units)	1952-78	3,034,465
	Total Hydro-Conventional	(87 units)	1903-83	320,910**
	Total Hydro-Pumped Storage	(7 units)	1928-73	1,110,350
	Total Internal Combustion	(23 units)	1966-86	562,400
	Total NU System Generating Plant			
	Including Regional Yankees	(142 units)		8,313,494
	Excluding Regional Yankees	(139 units)		7,793,303

*Claimed capability represents winter ratings as of December 31, 1995.

**Total Hydro-Conventional capability includes the Cobble Mtn. plant's 33,960 kW which is leased from the City of Springfield, MA.

Franchises

NU's operating subsidiaries hold numerous franchises in the territories served by them. For more information regarding recent judicial, regulatory and legislative decisions and initiatives that may affect the terms under which the System companies provide electric service in their franchised territories, see "Connecticut Retail Rates - Electric Industry Restructuring in Connecticut;" "New Hampshire Retail Rates - Electric Industry Restructuring in New Hampshire;" and "Massachusetts Retail Rates - Electric Industry Restructuring in Massachusetts," and "Item 3. Legal Proceedings."

CL&P. Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, CL&P has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to sell electricity in the respective areas in which it is now supplying such service.

In addition to the right to sell electricity as set forth above, the franchises of CL&P include, among others, rights and powers to manufacture, generate, purchase, transmit and distribute electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of CL&P include the power of eminent domain.

PSNH. Subject to the power of alteration, amendment or repeal by the General Court (legislature) of the State of New Hampshire and subject to certain approvals, permits and consents of public authority and others prescribed by statute, PSNH has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to sell electricity in the respective areas in which it is now supplying such service.

In addition to the right to sell electricity as set forth above, the franchises of PSNH include, among others, rights and powers to manufacture, generate, purchase, transmit and distribute electricity, to sell electricity at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of PSNH include the power of eminent domain.

NNECO. Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, NNECO has a valid franchise free from burdensome restrictions to sell electricity to utility companies doing an electric business in Connecticut and other states.

In addition to the right to sell electricity as set forth above, the franchise of NNECO includes, among others, rights and powers to manufacture, generate and transmit electricity, and to erect and maintain facilities on certain public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law.

WMECO. WMECO is authorized by its charter to conduct its electric business in the territories served by it, and has locations in the public highways for transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only, and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. In addition, WMECO has been granted easements for its lines in the Massachusetts Turnpike by the Massachusetts Turnpike Authority.

HWP and Holyoke Power and Electric Company (HP&E). HWP, and its wholly owned subsidiary HP&E, are authorized by their charters to conduct their businesses in the territories served by them. HWP's electric business is subject to the restriction that sales be made by written contract in amounts of not less than 100 horsepower, except for municipal customers in the counties of Hampden or Hampshire, Massachusetts and except for customers who occupy property in which HWP has a financial interest, by ownership or purchase money mortgage. HWP also has certain dam and canal and related rights, all subject to such consents and approvals of public authorities and others as may be required by law. The two companies have locations in the public highways for their transmission and distribution lines. Such locations are granted pursuant to the laws of Massachusetts by the Department of Public Works of Massachusetts or local municipal authorities and are of unlimited duration, but the rights thereby granted are not vested. Such locations are for specific lines only and, for extensions of lines in public highways, further similar locations must be obtained from the Department of Public Works of Massachusetts or the local municipal authorities. The two companies have no other utility franchises.

NAEC. NAEC is authorized by the NHPUC to own and operate its interest in Seabrook 1.

ITEM 3. LEGAL PROCEEDINGS

1. Litigation Relating to Electric and Magnetic Fields

In December 1991, NU and CL&P were sued in Connecticut Superior Court by Melissa Bullock, a nineteen-year old woman, and her mother, Suzanne Bullock, both residents of 28 Meadow Street in Guilford, Connecticut. The plaintiffs allege that they have lived in close proximity to CL&P's Meadow Street substation and distribution lines since 1979. The suit claims that Melissa Bullock suffers from a form of brain cancer and related physical and psychological injuries, which were "brought on as a result of exposure in her home to electromagnetic radiation generated by the defendants." Suzanne Bullock claims various physical and psychological injuries, and a diminution in the value of her property. The various counts against NU and CL&P include allegations of negligence, product liability, nuisance, unfair trade practices and strict liability. The suit seeks monetary damages, both compensatory and punitive, in as-yet unspecified amounts, as well as an injunction to cease emission of "dangerous levels" of electric and magnetic fields (EMF) into the plaintiffs' home. The plaintiffs are represented in part by counsel with a nationwide emphasis on similar litigation, and management considers this lawsuit to be a test case. The case is presently in the pre-trial discovery process. Trial is not anticipated until 1997.

In January 1992, a related lawsuit by two other plaintiffs also alleging cancer from EMF emanating from CL&P's Meadow Street substation and distribution lines was served on CL&P and NU. The plaintiffs are represented by the same counsel as the Bullocks, and the claims are nearly identical to the Bullocks' suit. This case is also in the pretrial discovery process; a trial date is not yet known.

Management believes that the allegations that EMF caused or contributed to the plaintiffs' illnesses are not supported by current scientific studies. NU and CL&P intend to defend the lawsuits vigorously. For information on EMF studies and state and federal initiatives, see "Item 1. Business - Regulatory and Environmental Matters - Electric and Magnetic Fields."

2. Southeastern Connecticut Regional Resources Recovery Authority (SCRRRA) - Application of the Municipal Rate

This matter involves three separate disputes over the rates that apply to CL&P's purchases of the generation of the SCRRRA project in Preston, Connecticut.

Municipal Rate Litigation: In 1990, CL&P initiated a challenge in federal district court to the DPUC's approval of an electricity purchase contract for the SCRRRA project under Connecticut's so-called "municipal rate law." Under this law, CL&P would be required to purchase a portion of the electricity from the resource recovery facility at a rate equal to the retail rate that CL&P charges municipalities for electricity ("municipal rate"), which is significantly higher than CL&P's avoided costs. The district court subsequently ordered the parties to seek FERC's resolution of this matter. On January 11, 1995, FERC ruled that a state cannot require an electric utility to enter into a contract paying a qualifying facility more than the utility's avoided costs. On April 12, 1995, FERC denied several petitions for rehearing and reaffirmed its ruling. SCRRRA and other participants in the FERC proceeding have appealed FERC's ruling to the United States Court of Appeals. FERC moved to dismiss the appeal on jurisdictional grounds, which motion is still pending. Should CL&P ultimately prevail, the benefits to CL&P customers would be approximately $14.5 million.

Non-Participant Towns: CL&P also contested SCRRRA's claim that CL&P must pay the municipal rate for the portion of the project's electricity that is derived from the trash of towns that are not long-term participants in the project. On April 20, 1994, the DPUC granted SCRRRA's request that the municipal rate be made applicable to the non-participant's portion of electricity.

On June 9, 1994, CL&P filed an appeal of the DPUC's ruling in the Hartford Superior Court. A total of approximately $3.5 million is in dispute for the years 1992 through 1994. The rate CL&P would be required to pay would also be substantially higher in later years if the DPUC's ruling is upheld. On February 6, 1995, the Superior Court granted the SCRRRA's motion to stay this proceeding until FERC issues a final decision on the municipal rate law. This case could be moot once the FERC decision is final.

Excess Capacity: CL&P also contested SCRRRA's claim that CL&P must purchase, at the applicable contract rates (each of which is higher than CL&P's current avoided costs), any excess of the project's generation above 13.85 MW per hour. On May 3, 1994, the Connecticut Appellate Court affirmed a Superior Court ruling that the DPUC should decide this issue. On September 20 1995, the DPUC ruled that the project's electricity sales under the contract are limited to no more than an average of 13.85 MW in any month. If the current level of plant operations continues CL&P's total savings would be in the range of $11.4 million (present worth basis) over the contract's entire term. In November 1995, CL&P and SCRRRA each filed appeals of the DPUC decision in Hartford Superior Court. CL&P maintains that its purchase obligation is limited to 13.85 MW applied on an hourly basis (instead of on a monthly basis), while SCRRRA maintains that CL&P's purchase obligation is not limited to 13.85 MW. These appeals are now in the briefing stage, after which the case will wait assignment to a judge for oral argument.

3. CL&P's 1992-1993 Retail Rate Case

In June 1993, the DPUC issued a decision approving a multi-year rate plan for CL&P. Two appeals have been filed from the 1993 Decision, one by CL&P and the other by the Connecticut Office of Consumer Counsel (OCC) and the City of Hartford (City). The two appeals were consolidated, and in May 1994, the City's appeal was dismissed by the Hartford Superior Court on jurisdictional grounds. The City appealed that dismissal to the Connecticut Appellate Court. The Supreme Court of Connecticut transferred the jurisdictional issue to itself and, in August 1995, affirmed the lower court's dismissal of the City. The City filed several post-decision motions, which the Supreme Court subsequently denied on September 13, 1995. The OCC's appeal is now proceeding in Hartford Superior Court. The other appeal, CL&P's challenge to certain aspects of the rate decision, is also proceeding in Hartford Superior Court.

4. Connecticut DPUC - CL&P's Petition for Declaratory Ruling Regarding Proposed Retail Sales of Electricity by Texas-Ohio Power, Inc. (TOP)

On August 3, 1995, CL&P filed a petition for declaratory rulings with the DPUC to determine whether TOP, which built a small congeneration plant in Manchester, Connecticut, can sell electricity from the facility to two CL&P retail customers in Manchester. The plant is located on property leased from one of the two customers. TOP expected to sell electricity to the other customer, a manufacturing facility located on adjacent property, via a 500 foot distribution line. TOP is a unit of Texas-Ohio Gas, a Houston-based gas pipeline operator and marketer. CL&P's petition pointed to the fact that CL&P has a franchised right to sell electricity in Manchester and TOP has not been authorized to compete by engaging in retail electricity sales within that territory. The petition also requested that the DPUC rule that, under Connecticut statutes, as well as judicial and DPUC decisions interpreting Connecticut law, TOP is prohibited from selling electricity at retail in Connecticut.

On December 4, 1995, CL&P informed the DPUC that it had entered into a flex rate contract with one of the two retail customers thereby retaining them as a customer and mooting the need for the DPUC to decide the issue of sales by a private power producer to an off-site customer. However, on December 6, 1995, the DPUC acted on CL&P's original petition and issued a final decision denying all of the specific declaratory rulings requested by CL&P. The DPUC concluded that, because TOP's project would not use the public streets, it did not require specific legislative authorization to make retail sales of electricity. Further, the DPUC found that specific statutory prohibitions against selling electricity at retail did not apply to TOP.

On January 17, 1996, CL&P appealed the DPUC's decision to the Hartford Superior Court. CL&P's appeal asks the Court to reverse the DPUC decision, insofar as it concludes that TOP is not prohibited from making retail electric sales in Connecticut, and to vacate the portions of the decision that deal with electricity sales to off-site customers. NU cannot predict the outcome of this proceeding or its ultimate effect on the System.

5. FERC - PSNH Acquisition Case

In 1992, FERC's approval of NU's acquisition of PSNH was appealed to the United States Court of Appeals for the First Circuit (Court). The Court affirmed the decision approving the merger but ordered FERC to address whether, if FERC had applied a more stringent "public interest standard" to the Seabrook power contract, any modifications would have been necessary. Purporting to apply this standard, FERC reaffirmed certain modifications to the contract, interpreting the standard liberally to allow it to intervene in contracts on behalf of non-parties to the contract. NU requested rehearing, arguing that FERC had not applied the appropriate standard, which request was denied by FERC in July 1994. In September 1994, NU filed a Petition for Review with the First Circuit Court of Appeals concerning FERC's application of a "public interest standard" to the Seabrook Power Contract. On May 23, 1995, the Court affirmed FERC's order. The Court held that FERC had correctly applied the "public interest standard" to modify terms of the contract. The order affects only future changes to the Seabrook Power Contract, including changes to decommissioning charges and rate of return.

6. New Hampshire Office of Consumer Advocate and the Campaign for Ratepayer Rights Case

On November 1, 1995, the New Hampshire Office of Consumer Advocate (OCA) and the Campaign for Ratepayers Rights filed suit in Superior Court against the NHPUC seeking a declaratory ruling that special contracts entered into by and between PSNH and certain retail customers are prohibited by the 1989 rate agreement between PSNH and the State of New Hampshire (Rate Agreement). The petition is based on an alleged inconsistency between the New Hampshire statute that allows special contracts agreed to by a utility and a customer when deemed appropriate by the NHPUC and the legislation accepting the Rate Agreement wherein PSNH received protection against NHPUC actions fixing rates other than in the manner agreed upon in the Rate Agreement. The petition alleges that the special contracts constitute a breach of the Rate Agreement by PSNH, thereby estopping PSNH from claiming benefits under the Rate Agreement. On December 11, 1995, the Superior Court denied a request for an emergency injunction which would have prevented the NHPUC from authorizing any further special contracts between PSNH and large industrial customers. The New Hampshire Attorney General is representing the NHPUC in this action. However, OCA disputes the New Hampshire Attorney General's authority to provide such representation. While NU believes this proceeding should be dismissed on procedural grounds, it cannot predict the outcome of this proceeding or its ultimate effect on the System.

7. Tax Litigation

In 1991, per Connecticut statute, the Town of Haddam performed a town-wide revaluation of the Connecticut Yankee (CY) property in that town. Based on the report of the engineering firm hired by the town to perform the revaluation, Haddam determined that the full fair-market value of the property, as of October 1, 1991, was $840 million. At that time, CY's net-book value was $245 million.

In March 1992, CY appealed this excessive valuation to Haddam's Board of Tax Review, which subsequently rejected CY's appeal. CY then, in July 1992, appealed to the Middletown Superior Court. At issue is the fair market value of utility property. NU believes that the assessments should be based on a fair market value that approximates net book cost. This is the assessment level that taxing authorities are predominantly using throughout Connecticut. However, Haddam advocates a method that approximates reproduction costs.

Two expert appraisals of the property were prepared for CY's use in the appeal - 1) Stone & Webster's determination that the full fair-market value of CY's property, as of October 1, 1991, was $230 million and 2) AUS Consulting of Milwaukee's finding of a value of $219.4 million. Trial began in Middletown Superior Court in early December 1995, and a decision is expected during the first half of 1996. NU cannot predict the outcome of this proceeding or its ultimate effect on the System.

8. Other Legal Proceedings

The following sections of Item 1 "Business" discuss additional legal proceedings: See "Competition and Marketing" for information regarding a DPUC proceeding on guidelines for CL&P's flexible rate agreements; "Wholesale Marketing" for information on a PSNH complaint filed against NHEC at the FERC; "Rates" for information about CL&P's rate and fuel clause adjustment clause proceedings, NHPUC proceedings involving Freedom Energy Company, New Hampshire's LEEPA statute and PSNH's franchise rights, and the Seabrook Power Contract; "Electric Operations -- Generation and Transmission" for information about proceedings relating to power and transmission issues; "Electric Operations -- Nuclear Generation" for information related to nuclear plant performance, nuclear fuel enrichment pricing, high-level and low-level radioactive waste disposal, decommissioning matters and NRC regulation; "Regulatory and Environmental Matters" for information about proceedings involving surface water and air quality, toxic substances and hazardous waste, electric and magnetic fields, licensing of hydroelectric projects, and other matters.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No Event that would be described in response to this item occurred with respect to NU, CL&P, WMECO, PSNH or NAEC.

PART II

Item 5. Market for the Registrants' Common Equity and Related Shareholder Matters

NU. The common shares of NU are listed on the New York Stock Exchange. The ticket symbol is "NU," although it is frequently presented as "Noeast Util" and/or "NE Util" in various financial publications. The high and low sales prices for the past two years, by quarters, are shown below.

Year	Quarter	High	Low
1995	First	$24 1/4	21
	Second	23 7/8	21 3/8
	Third	24 1/2	22
	Fourth	25 3/8	23 1/2
1994	First	$25 3/4	23
	Second	24 7/8	21 1/4
	Third	24 5/8	20 3/8
	Fourth	23 3/8	21 1/4

As of January 31, 1996, there were 129,943 common shareholders of record of NU. As of the same date, there were a total of 135,985,056 common shares issued, including approximately 8.5 million unallocated ESOP shares held in the ESOP trust.

NU declared and paid quarterly dividends of $0.44 in 1995 and $0.44 in 1994. On January 23, 1996, the Board of Trustees declared a dividend of $0.44 per share, payable on March 31, 1996 to holders of record on March 1, 1996. The declaration of future dividends may vary depending on capital requirements and income as well as financial and other conditions existing at the time.

Information with respect to dividend restrictions for NU and its subsidiaries is contained in Item 1. Business under the caption "Financing Program - Financing Limitations" and in Note (b) to the "Consolidated Statements of Common Shareholders' Equity" on page 30 of NU's 1996 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P, PSNH, WMECO, and NAEC. The information required by this item is not applicable because the common stock of CL&P, PSNH, WMECO, and NAEC is held solely by NU.

Item 6. Selected Financial Data

NU. Reference is made to information under the heading "Selected Consolidated Financial Data" contained on page 45 of NU's 1995 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Selected Financial Data" contained on page 35 of CL&P's 1995 Annual Report, which information is Incorporated herein by reference.

PSNH. Reference is made to information under the heading "Selected Financial Data" contained on pages 32 and 33 of PSNH's 1995 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Selected Financial Data" contained on page 33 of WMECO's 1995 Annual Report, which information is incorporated herein by reference.

NAEC. Reference is made to information under the heading "Selected Financial Data" contained on page 21 of NAEC's 1995 Annual Report, which information is incorporated herein by reference.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

NU. Reference is made to information under the heading "Management's Discussion and Analysis" contained on pages 15 through 21 in NU's 1995 Annual Report to Shareholders, which information is incorporated herein by reference.

CL&P. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained on pages 29 through 34 in CL&P's 1995 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained on pages 26 through 31 in PSNH's 1995 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained on pages 27 through 32 in WMECO's 1995 Annual Report, which information is incorporated herein by reference.

NAEC. Reference is made to information under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained on pages 17 through 20 in NAEC's 1995 Annual Report, which information is incorporated herein by reference.

Item 8. Financial Statements and Supplementary Data

NU. Reference is made to information under the headings "Company Report," "Report of Independent Public Accountants," "Consolidated Statements of Income," "Consolidated Statements of Cash Flows," "Consolidated Statements of Income Taxes," "Consolidated Balance Sheets," "Consolidated Statements of Capitalization," "Consolidated Statements of Common Shareholders' Equity," "Notes to Consolidated Financial Statements," and "Consolidated Statements of Quarterly Financial Data" contained on pages 22 through 44 in NU's 1995. Annual Report to Shareholders, which information, which information is incorporated herein by reference.

CL&P. Reference is made to information under the headings "Consolidated Balance Sheets," "Consolidated Statements of Income," "Consolidated Statements of Cash Flows," "Consolidated Statements of Common Stockholder's Equity," "Notes to Consolidated Financial Statements," "Report of Independent Public Accountants," and "Statements of Quarterly Financial Data" contained on pages 2 through 28 and page 35 in CL&P's 1995 Annual Report, which information is incorporated herein by reference.

PSNH. Reference is made to information under the headings "Balance Sheets," "Statements of Income," "Statements of Cash Flows," "Statements of Common Equity," "Notes to Financial Statements," "Report of Independent Public Accountants," "Independent Auditors' Report," and "Statements of Quarterly Financial Data" contained on pages 2 through 25 and page 34 in PSNH's 1995 Annual Report, which information is incorporated herein by reference.

WMECO. Reference is made to information under the headings "Balance Sheets," "Statements of Income," "Statements of Cash Flows," "Statements of Common Stockholder's Equity," "Notes to Financial Statements," "Report of Independent Public Accountants," and "Statements of Quarterly Financial Data" contained on pages 2 through 26 and page 33 in WMECO's 1995 Annual Report, which information is incorporated herein by reference.

NAEC. Reference is made to information under the headings "Balance Sheet," "Statement of Income," "Statement of Cash Flows," "Statement of Common Stockholder's Equity," "Notes to Financial Statements," "Report of Independent Public Accountants," and "Statement of Quarterly Financial Data" contained on pages 2 through 16 and page 21 in NAEC's 1995 Annual Report which information is incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

No event that would be described in response to this item has occurred with respect to NU, CL&P, PSNH, WMECO, or NAEC.

PART III

Item 10. Directors and Executive Officers of the Registrants

NU.

In addition to the information provided below concerning the executive officers of NU, incorporated herein by reference is the information contained in the sections "Proxy Statement," "Committee Composition and Responsibility," "Common Stock Ownership of Certain Beneficial Owners," "Common Stock Ownership of Management," "Compensation of Trustees," "Summary Compensation Table," "Pension Benefits," and "Report on Executive Compensation" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, dated April 1, 1996 and filed with the Commission pursuant to Rule 14a-6 under the Securities Exchange Act of 1934 (the Act).

Name	Positions Held	First Elected an Officer	First Elected a Trustee
Bernard M. Fox	CHB, P, CEO, T	05/01/83	05/20/86

CL&P.

Name	Positions Held	First Elected an Officer	First Elected a Director
Robert G. Abair	D	-	01/01/89
Robert E. Busch	P, D	06/01/87	06/01/87
John H. Forsgren	EVP, CFO	02/01/96	-
Bernard M. Fox	CH, D	05/15/81	05/01/83
William T. Frain, Jr.	D	-	02/01/94
Cheryl W. Grisé	SVP, CAO, D	06/01/91	01/01/94
Barry Ilberman	VP	02/01/89	-
John B. Keane	VP, TR, D	08/01/92	08/01/92
Francis L. Kinney	SVP	04/24/74	-
Hugh C. MacKenzie	P, D	07/01/88	06/06/90
John J. Roman	VP, CONT	04/01/92	-
Robert P. Wax	VP, SEC, GC	08/01/92	-

PSNH.

Name	Positions Held	First Elected an Officer	First Elected a Director
Robert E. Busch	P	06/05/92	
John C. Collins	D	-	10/19/92
John H. Forsgren	EVP, CFO	02/01/96	-
Bernard M. Fox	CH, CEO, D	06/05/92	06/05/92
William T. Frain, Jr.	P, COO, D	03/18/71	02/01/94
Cheryl W. Grisé	D		02/06/95
Barry Ilberman	VP	07/01/94	-
Gerald Letendre	D	-	10/19/92
Hugh C. MacKenzie	D	-	02/01/94
Jane E. Newman	D	-	10/19/92
John J. Roman	VP, CONT	04/01/92	-
Robert P. Wax	VP,SEC,GC,D	08/01/92	02/01/93

WMECO.

Name	Positions Held	First Elected an Officer	First Elected a Director
Robert G. Abair	VP, CAO, D	09/06/88	01/01/89
Robert E. Busch	P, D	06/01/87	06/01/87
John H. Forsgren	EVP, CFO	02/01/96	-
Bernard M. Fox	C, D	05/15/81	05/01/83
William T. Frain, Jr.	D	-	02/01/94
Cheryl W. Grisé	SVP, D	06/01/91	01/01/94
Barry Ilberman	VP	02/01/89	-
John B. Keane	VP, TR, D	08/01/92	08/01/92
Francis L. Kinney	SVP	04/24/74	-
Hugh C. MacKenzie	P, D	07/01/88	06/06/90
John J. Roman	VP, CONT	04/01/92	-
Robert P. Wax	VP, SEC, AC, GC	08/01/92	-

NAEC.

Name	Positions Held	First Elected an Officer	First Elected a Director
Robert E. Busch	P, D	10/21/91	10/16/91
Ted C. Feigenbaum	EVP, CNO, D	10/21/91	10/16/91
John H. Forsgren	EVP, CFO	02/01/96	-
Bernard M. Fox	C, CEO, D	10/21/91	10/16/91
William T. Frain, Jr.	D	-	02/01/94
Cheryl W. Grisé	SVP, CAO, D	10/21/91	01/01/94
Barry Ilberman	VP	01/29/92	-
Francis L. Kinney	SVP	10/21/91	-
John B. Keane	VP, TR, D	08/01/92	08/01/92
Hugh C. MacKenzie	D	-	01/01/94
John J. Roman	VP, CONT	04/01/92	-
Robert P. Wax	VP, SEC, GC	08/01/92	-

Key:

AC - Assistant Clerk
CAO - Chief Administrative Office
CEO - Chief Executive Officer
CFO - Chief Financial Officer
CH - Chairman
CHB - Chairman of the Board
CNO - Chief Nuclear Officer
COO - Chief Operating Officer
CONT - Controller
D - Director
EVP - Executive Vice President
GC - General Counsel
P - President
SEC - Secretary
SVP - Senior Vice President
T - Trustee
TR - Treasurer
VP - Vice President

Name	Age	Business Experience During Past 5 Years
Robert G. Abair (1)	57	Elected Vice President and Chief Administrative Officer of WMECO in 1988.
Robert E. Busch (2)	49	Elected President-Energy Resources Group of NU, CL&P, PSNH and WMECO February, 1996 and President of NAEC in 1994; previously Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH, and WMECO since 1992; Executive Vice President and Chief Financial Officer of NAEC since 1992; Senior Vice President and Chief Financial Officer of NU, CL&P and WMECO since 1990.
John C. Collins (3)	51	Executive Vice President, Lahey Clinic, since 1995. Previously Chief Executive Officer, The Hitchcock Clinic, Dartmouth - Hitchcock Medical Center from 1977 to 1995.
Ted C. Feigenbaum (4)	45	Elected Executive Vice President and Chief Nuclear Officer of NAEC February, 1996; previously Senior Vice President of NAEC since 1991; Senior Vice President and Chief Nuclear Officer of PSNH June, 1992 to August, 1992; President and Chief Executive Officer - New Hampshire Yankee Division of PSNH October, 1990 to June, 1992 and Chief Nuclear Production Officer of PSNH January, 1990 to June, 1992.
John H. Forsgren	49	Elected Executive Vice President and Chief Financial Officer of NU, CL&P, PSNH, WMECO and NAEC February, 1996; previously Managing Director of Chase Manhattan Bank since 1995; Executive Vice President of Sun International Investments, LTD since 1994; and Senior Vice President-Chief Financial Officer of Euro Disney, The Walt Disney Company.
Bernard M. Fox (5)	53	Elected Chairman of the Board, President and Chief Executive Officer of NU, Chairman of CL&P, PSNH, WMECO and NAEC, and Chief Executive Officer of PSNH and NAEC in 1995; previously Vice Chairman of CL&P and WMECO, and Vice Chairman and Chief Executive Officer of NAEC since 1994; Chief Executive Officer of NU, CL&P, PSNH, WMECO and NAEC in 1993; President and Chief Operating Officer of NU, CL&P and WMECO in 1990 and NAEC since 1991; Vice Chairman of PSNH since 1992.
William T. Frain, Jr. (6)	54	Elected President and Chief Operating Officer of PSNH in 1994; previously Senior Vice President of PSNH since 1992; previously Vice President and Treasurer of PSNH since 1991.

Cheryl W. Grise	43	Elected Senior Vice President and Chief Administrative Officer of CL&P, PSNH and NAEC, and Senior Vice President of WMECO in 1995; previously Senior Vice President-Human Resources and Administrative Services of CL&P, WMECO and NAEC since 1994; Vice President-Human Resources of NAEC since 1992 and of CL&P and WMECO since 1991.
Barry Ilberman	46	Elected Vice President-Corporate and Environmental Affairs of CL&P, PSNH, WMECO and NAEC, in 1994; previously Vice President-Corporate Planning of CL&P, WMECO since 1992; Vice President-Corporate Business Practices of CL&P, WMECO since 1991; and Vice President-Human Resources of CLP, WMECO since 1989.
John B. Keane (7)	49	Elected Vice President and Treasurer of NU, CL&P, PSNH, WMECO and NAEC in 1993; previously Vice President, Secretary and General Counsel-Corporate of NU, CL&P and WMECO since 1993; Vice President, Assistant Secretary and General Counsel-Corporate of PSNH and NAEC, Vice President, Secretary and General Counsel-Corporate of NU and CL&P, and Vice President, Secretary, Assistant Clerk and General Counsel-Corporate of WMECO since 1992; previously Associate General Counsel of NUSCO since 1985.
Francis L. Kinney (8)	63	Elected Senior Vice President-Governmental Affairs of CL&P, WMECO and NAEC in 1994; previously Vice President-Public Affairs of NAEC since 1992 and of CL&P and WMECO since 1978.
Gerald Letendre	54	President, Diamond Casting & Machine Co., Inc. since 1972.
Hugh C. MacKenzie (9)	53	Elected President-Retail Business Group of NU Feburary, 1996 and President of CL&P and WMECO in 1994; previously Senior Vice President-Customer Service Operations of CL&P and WMECO since 1990.
Jane E. Newman (10)	50	Executive Vice President, Exeter Trust Company since 1995. Previously President, Coastal Broadcasting Corporation since 1992; previously Assistant to the President of the United State for Management and Administration from 1989 to 1991.

John J. Roman	42	Elected Vice President and Controller of NU, CL&P, PSNH, WMECO and NAEC in 1995; previously Assistant Controller of CL&P, PSNH, WMECO and NAEC since 1992.
Robert P. Wax	47	Elected Vice President, Secretary and General Counsel of PSNH and NAEC in 1994; elected Vice President, Secretary and General Counsel of NU and CL&P and Vice President, Secretary, Assistant Clerk and General Counsel of WMECO in 1993; previously Vice President, Assistant Secretary and General Counsel of PSNH and NAEC since 1993; previously Vice President and General Counsel-Regulatory of NU, CL&P, PSNH, WMECO, and NAEC since 1992; previously Associate General Counsel of NUSCO since 1985.

(1) Trustee of Easthampton Savings Bank.
(2) Director of Connecticut Yankee Atomic Power Company.
(3) Director of Fleet Bank - New Hampshire and Hamden Assurance Company Limited.
(4) Director of Connecticut Yankee Atomic Power Company and Maine Yankee Atomic Power Company.
(5) Director of The Institute of Living, The Institute of Nuclear Power Operations, The Connecticut Business and Industry Association, Mount Holyoke College, Fleet Financial Group, CIGNA Corporation, Connecticut Yankee Atomic Power Company and The Dexter Corporation.
(6) Director of Connecticut Yankee Atomic Power Company, the Business and Industry Association of New Hampshire, the Greater Manchester Chamber of Commerce; Trustee of Optima Health, Inc., and Saint Anselm's College.
(7) Director of Maine Yankee Atomic Power Company, Vermont Yankee Nuclear Power Corporation, Yankee Atomic Electric Company and Connecticut Yankee Atomic Power Company
(8) Director of Mid-Conn Bank.
(9) Director of Connecticut Yankee Atomic Power Company.
(10) Director of Exeter Trust Company, Perini Corporation, NYNEX Telecommunications and Consumers Water Company.

There are no family relationships between any director or executive officer and any other director or executive officer of NU, CL&P, PSNH, WMECO or NAEC.

Item 11. Executive Compensation

NU.

Incorporated herein by reference is the information contained in the sections "Summary Compensation Table," "Pension Benefits," and "Report on Executive Compensation" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, dated April 1, 1996 and filed with the Commission pursuant to Rule 14a-6 under the Act.

SUMMARY COMPENSATION TABLE

The following table presents the cash and non-cash compensation received by the CEO and the next four highest paid executive officers of the System, and by twc retired executive officers who would have been among the five highest paid executive officers but for their retirement, in accordance with rules of the Securities and Exchange Commission (SEC):

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus($) (1)	Other Annual Compensation($)	Restricted Stock Awards ($)	Options/ Stock Appreciation Rights (#)	Long Term Incentive Program Payouts ($)	All Other Compensation($) (2)
Bernard M. Fox(4)	1995	551,300	(3)	None	None	None	130,165	7,350
Chairman of the Board,	1994	544,459	308,896	None	None	None	115,771	4,500
President and Chief Executive Officer	1993	478,775	180,780	None	None	None	61,155	7,033
Robert E. Busch(5)	1995	350,000	(3)	None	None	None	63,100	7,350
President - Energy	1994	346,122	173,366	None	None	None	44,073	4,500
Resources Group	1993	255,915	78,673	None	None	None	32,337	7,072
Hugh C. MacKenzie(6)	1995	247,665	(3)	None	None	None	46,789	7,350
President - Retail	1994	245,832	113,416	None	None	None	40,449	4,500
Business Group	1993	192,502	51,765	None	None	None	28,000	5,775
Francis L. Kinney(7)	1995	190,100	(3)	None	None	None	29,808	5,584
Senior Vice	1994	191,303	57,425	None	None	None	24,549	4,500
President - Governmental Affairs (principal subsidiaries)	1993	188,090	28,620	None	None	None	27,020	5,423
Cheryl W. Grise(8)	1995	178,885	(3)	None	None	None	24,834	5,361
Senior Vice President -	1994	169,354	64,412	None	None	None	17,616	4,491
Chief Administrative Officer (principal subsidiaries)	1993	136,475	25,728	None	None	None	0	4,094

William B. Ellis(9)	1995	249,420	(3)	None	None	None	158,393	7,350
Retired	1994	457,769	129,742	None	None	None	185,003	4,500
	1993	521,250	160,693	None	None	None	87,363	None
John F. Opeka(10)	1995	275,449	(3)	None	None	None	56,779	7,350
Retired	1994	283,069	65,775	None	None	None	54,556	4,500
	1993	277,304	58,259	None	None	None	40,014	6,875

Notes:

(1) Awards under the 1993 and 1994 short-term programs of the Northeast Utilities Executive Incentive Plan (EIP) were paid the next year in the form of cash. In accordance with the requirements of the SEC, these awards are included as "bonus" in the years earned.

(2) "All Other Compensation" consists of employer matching contributions under the Northeast Utilities Service Company Supplemental Retirement and Savings Plan, generally available to all eligible employees.

(3) Awards under the short-term program of the EIP have typically been made by the Committee on Organization, Compensation and Board Affairs in April each year.

(4) Mr. Fox is a Director and Executive Officer of CL&P, PSNH, WMECO and NAEC.

(5) Mr. Busch is a Director of CL&P, WMECO and NAEC and an Executive Officer of CL&P, PSNH, WMECO and NAEC.

(6) Mr. MacKenzie is a Director of CL&P, PSNH, WMECO and NAEC and an Executive Officer of CL&P and WMECO.

(7) Mr. Kinney is an Executive Officer of CL&P, WMECO and NAEC.

(8) Mrs. Grisé is a Director of CL&P, PSNH, WMECO and NAEC and an Executive Officer of CL&P, WMECO and NAEC.

(9) Mr. Ellis retired as Chairman of the Board and a Trustee of Northeast Utilities, and as Chairman and a Director of CL&P, PSNH, WMECO, and NAEC on August 1, 1995.

(10) Mr. Opeka retired as Executive Vice President - Nuclear of NAEC and as a Director of NAEC, CL&P and WMECO on November 1, 1995.

PENSION BENEFITS

The following table shows the estimated annual retirement benefits payable to an executive officer of Northeast Utilities upon retirement, assuming that retirement occurs at age 65 and that the officer is at that time not only eligible for a pension benefit under the Northeast Utilities Service Company Retirement Plan (the Retirement Plan) but also eligible for the "make-whole benefit" and the "target benefit" under the Supplemental Executive Retirement Plan for Officers of Northeast Utilities System Companies (the Supplemental Plan). The Supplemental Plan is a non-qualified pension plan providing supplemental retirement income to system officers. The "make-whole benefit" under the Supplemental Plan, available to all officers, makes up for benefits lost through application of certain tax code limitations on the benefits that may be provided under the Retirement Plan and includes as "compensation" awards under the Executive Incentive Compensation Program and Executive Incentive Plan and deferred compensation (as earned). The "target benefit" further supplements these benefits and is available to officers at the Senior Vice President level and higher who are selected by the Board of Trustees to participate in the target benefit and who remain in the employ of Northeast Utilities companies until at least age 60 (unless the Board of Trustees sets an earlier age). Each of the executive officers of Northeast Utilities named in the "Summary Compensation Table" is currently eligible for a target benefit.

The benefits presented are based on a straight life annuity beginning at age 65 and do not take into account any reduction for joint and survivorship annuity payments.

ANNUAL TARGET BENEFIT

Final Average Compensation	**Years of Credited Service**				
	15	20	25	30	35
$200,000	$72,000	$96,000	$120,000	$120,000	$120,000
250,000	90,000	120,000	150,000	150,000	150,000
300,000	108,000	144,000	180,000	180,000	180,000
350,000	126,000	168,000	210,000	210,000	210,000
400,000	144,000	192,000	240,000	240,000	240,000
450,000	162,000	216,000	270,000	270,000	270,000
500,000	180,000	240,000	300,000	300,000	300,000
600,000	216,000	288,000	360,000	360,000	360,000
700,000	252,000	336,000	420,000	420,000	420,000
800,000	288,000	384,000	480,000	480,000	480,000
900,000	324,000	432,000	540,000	540,000	540,000
1,000,000	360,000	480,000	600,000	600,000	600,000
1,100,000	396,000	528,000	660,000	660,000	660,000
1,200,000	432,000	576,000	720,000	720,000	720,000

Final average compensation for purposes of calculating the "target benefit" is the highest average annual compensation of the participant during any 36 consecutive months compensation was earned. Compensation taken into account under the "target benefit" described above includes salary, bonus, restricted stock awards, and long-term incentive payouts shown in the Summary Compensation Table, but does not include employer matching contributions under the 401(k) Plan. In the event that an officer's employment terminates because of disability, the retirement benefits shown above would be offset by the amount of any disability benefits payable to the recipient that are attributable to contributions made by Northeast Utilities and its subsidiaries under long term disability plans and policies.

As of December 31, 1995, the five executive officers named in the Summary Compensation Table above had the following years of credited service for retirement compensation purposes: Mr. Fox - 31, Mr. Busch - 22, Mr. MacKenzie - 30, Mr. Kinney - 34, and Mrs. Grisé - 15. Assuming that retirement were to occur at age 65 for these officers, retirement would occur with 43, 38, 41, 36 and 36 years of credited service, respectively.

In 1992, Northeast Utilities entered into an agreement with Mr. Fox to provide for an orderly Chief Executive Officer succession. The agreement states that if Mr. Fox is terminated as Chief Executive Officer without cause, he will be entitled to specified severance pay and benefits. Those benefits consist primarily of (i) two years' base pay, medical, dental and life insurance benefits; (ii) a supplemental retirement benefit equal to the difference between the target benefit he would be entitled to receive if he had reached the age of 55 on the termination date and the actual target benefit to which he is entitled as of the termination date; and (iii) a target benefit under the Supplemental Plan, notwithstanding that he might not have reached age 60 on the termination date and notwithstanding other forfeiture provisions of that plan. The agreement also provides specified death and disability benefits. The agreement does not address Mr. Fox's normal compensation and benefits, which are to be determined by the Committee on Organization, Compensation and Board Affairs and the Board in accordance with their customary practices. The agreement terminates two years after Northeast Utilities gives Mr. Fox a notice of termination, but no earlier than the date he becomes 55.

Item 12. Security Ownership of Certain Beneficial Owners and Management

NU.

Incorporated herein by reference is the information contained in the sections "Common Stock Ownership of Certain Beneficial Owners," "Common Stock Ownership of Management," "Compensation of Trustees," "Summary Compensation Table," "Pension Benefits," and "Report on Executive Compensation" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, dated April 1, 1996 and filed with the Commission pursuant to Rule 14a-6 under the Act.

CL&P, PSNH, WMECO and NAEC.

NU owns 100% of the outstanding common stock of registrants CL&P, PSNH, WMECO and NAEC. As of February 27, 1996, the Directors of CL&P, PSNH, WMECO and NAEC, beneficially owned the number of shares of each class of equity securities of NU listed below. No equity securities of CL&P, PSNH, WMECO or NAEC are owned by the Directors and Executive Officers of their respective companies.

CL&P, PSNH, WMECO, and NAEC DIRECTORS AND NAMED EXECUTIVE OFFICERS

Title Of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)		Percent of Class (2)
NU Common	Robert G. Abair(3)	6,489	(3,023)	
NU Common	Robert E. Busch(4)	10,074	(5,492)	
NU Common	John C. Collins(5)	25		
NU Common	Ted C. Feigenbaum(6)	474	(474)	
NU Common	John H. Forsgren(7)	0		
NU Common	Bernard M. Fox(8)	25,092	(3,597)	
NU Common	William T. Frain, Jr.(9)	1,793	(536)	
NU Common	Cheryl W. Grisé(10)	3,407	(1,116)	
NU Common	Barry Ilberman(11)	6,822	(3,156)	
NU Common	John B. Keane(12)	2,122	(1,475)	
NU Common	Francis L. Kinney(13)	3,697	(2,189)	
NU Common	Gerald Letendre(5)	0		
NU Common	Hugh C. MacKenzie(14)	8,047	(2,724)	
NU Common	Jane E. Newman(5)	0		
NU Common	John J. Roman(15)	1,624	(1,624)	
NU Common	Robert P. Wax(16)	2,791	(2,260)	

Amount beneficially owned by Directors and Executive Officers as a group

- CL&P	71,958 (27,192)	shares
- PSNH	59,675 (20,505)	shares
- WMECO	71,958 (27,192)	shares
- NAEC	65,943 (24,642)	shares

(1) Unless otherwise noted, each Director and Executive Officer of CL&P, PSNH, WMECO and NAEC has sole voting and investment power with respect to the listed shares. The numbers in parentheses reflect the number of shares owned by each Director and Executive Officer under the Northeast Utilities Service Company Supplemental Retirement and Savings Plan (401(k) Plan), as to which the Officer has no investment power.

(2) As of February 27, 1996 there were 136,023,358 common shares of NU outstanding. The percentage of such shares beneficially owned by any Director or Executive Officer, or by all Directors and Executive Officers of CL&P, PSNH, WMECO and NAEC as a group, does not exceed one percent.

(3) Mr. Abair is a Director of CL&P and WMECO.

(4) Mr. Busch is a Director of CL&P, WMECO and NAEC and an Executive Officer of CL&P, PSNH, WMECO and NAEC.

(5) Messrs. Collins, Letendre and Ms. Newman are Directors of PSNH. Mr. Collins shares voting and investment power with his wife for 25 shares.

(6) Mr. Feigenbaum is a Director and an Executive Officer of NAEC.

(7) Mr. Forsgren is an Executive Officer of CL&P, PSNH, WMECO and NAEC.

(8) Mr. Fox is a Director and Executive Officer of CL&P, PSNH, WMECO and NAEC. Mr. Fox shares voting and investment power with his wife for 3,031 of these shares. In addition, Mr. Fox's wife has sole voting and investment power for 140 shares as to which Mr. Fox disclaims beneficial ownership.

(9) Mr Frain is a Director of CL&P, PSNH, WMECO and NAEC and an Executive Officer of PSNH.

(10) Mrs. Grisé is a Director of CL&P, PSNH, WMECO and NAEC and an Executive Officer of CL&P, WMECO and NAEC.

(11) Mr. Ilberman is an Executive Officer of CL&P, PSNH, WMECO and NAEC. Mr. Ilberman shares voting and investment power with his wife for 290 of these shares and voting and investment power with his mother for 1,161 of these shares.

(12) Mr. Keane is a Director of CL&P, WMECO and NAEC.

(13) Mr. Kinney is an Executive Officer of CL&P, WMECO and NAEC. Mr. Kinney shares voting and investment power with his wife for 1,508 of these shares.

(14) Mr. MacKenzie is a Director of CL&P, PSNH, WMECO and NAEC and an Executive Officer of CL&P and WMECO. Mr. MacKenzie shares voting and investment power with his wife for 1,467 shares.

(15) Mr. Roman is an Executive Officer of CL&P, PSNH, WMECO and NAEC.

(16) Mr. Wax is a Director of PSNH and an Executive Officer of CL&P, PSNH, WMECO and NAEC.

Item 13. Certain Relationships and Related Transactions

NU.

Incorporated herein by reference is the information contained in the section "Certain Relationships and Related Transactions" of the definitive proxy statement for solicitation of proxies by NU's Board of Trustees, dated April 1, 1996 and filed with the Commission pursuant to Rule 14a-6 under the Act.

CL&P, PSNH, WMECO, and NAEC.

No relationships or transactions that would be described in response to this item exist now or existed during 1995 with respect to CL&P, PSNH, WMECO, and NAEC.

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a) 1. Financial Statements:

The Report of Independent Public Accountants and financial statements of NU, CL&P, PSNH, WMECO, and NAEC are hereby incorporated by reference and made a part of this report (see "Item 8. Financial Statements and Supplementary Data").

2. Schedules:

(b) Reports on Form 8-K:

NU, CL&P, PSNH, WMECO, and NAEC filed Form 8-Ks dated January 31, 1996 on January 31, 1996. This 8-K filing disclosed that the NRC had announced that the Millstone Nuclear Power Station had been placed on its "watch list."

NORTHEAST UTILITIES

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHEAST UTILITIES
(Registrant)

Date: March 13, 1996

By /s/Bernard M. Fox
Bernard M. Fox
Chairman of the Board,
President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 13, 1996	A Trustee, Chairman of the Board, President and Chief Executive Officer	/s/Bernard M. Fox Bernard M. Fox
March 13, 1996	Executive Vice President and Chief Financial Officer	/s/ John H. Forsgren John H. Forsgren
March 13, 1996	Vice President and Controller	/s/John J. Roman John J. Roman

NORTHEAST UTILITIES
SIGNATURES (CONT'D)

Date	Title	Signature
March 13, 1996	Trustee	/s/Alfred F. Boschulte Alfred F. Boschulte
March 13, 1996	Trustee	/s/Cotton Mather Cleveland Cotton Mather Cleveland
March 13, 1996	Trustee	/s/George David George David
March 13, 1996	Trustee	/s/E. Gail de Planque E. Gail de Planque
March 13, 1996	Trustee	/s/Gaynor N. Kelley Gaynor N. Kelley
March 13, 1996	Trustee	/s/Elizabeth T. Kennan Elizabeth T. Kennan
March 13, 1996	Trustee	/s/Denham C. Lunt, Jr. Denham C. Lunt, Jr.

NORTHEAST UTILITIES
SIGNATURES (CONT'D)

Date	Title	Signature
March 13, 1996	Trustee	/s/William J. Pape II William J. Pape II
March 13, 1996	Trustee	/s/Robert E. Patricelli Robert E. Patricelli
March 13, 1996	Trustee	/s/Norman C. Rasmussen Norman C. Rasmussen
March 13, 1996	Trustee	/s/John F. Swope John F. Swope
March 13, 1996	Trustee	/s/John F. Turner John F. Turner

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

Date: March 13, 1996

By /s/Bernard M. Fox
Bernard M. Fox
Chairman

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 13, 1996	Chairman and a Director	/s/Bernard M. Fox Bernard M. Fox
March 13, 1996	President and a Director	/s/Hugh C. MacKenzie Hugh C. MacKenzie
March 13, 1996	Executive Vice President and Chief Financial Officer	/s/ John H. Forsgren John H. Forsgren
March 13, 1996	Vice President and Controller	/s/John J. Roman John J. Roman

THE CONNECTICUT LIGHT AND POWER COMPANY

SIGNATURES (CONT'D)

Date	Title	Signature
March 13, 1996	Director	/s/Robert G. Abair Robert G. Abair
March 13, 1996	Director	/s/Robert E. Busch Robert E. Busch
March 13, 1996	Director	/s/William T. Frain, Jr. William T. Frain, Jr.
March 13, 1996	Director	/s/Cheryl W. Grisé Cheryl W. Grisé
March 13, 1996	Director	/s/John B. Keane John B. Keane

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
(Registrant)

Date: March 13, 1996

By /s/Bernard M. Fox
Bernard M. Fox
Chairman and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 13, 1996	Chairman, Chief Executive Officer and a Director	/s/Bernard M. Fox Bernard M. Fox
March 13, 1996	President, Chief Operating Officer and a Director	/s/William T. Frain, Jr. William T. Frain, Jr.
March 13, 1996	Executive Vice President and Chief Financial Officer	/s/ John H. Forsgren John H. Forsgren
March 13, 1996	Vice President and Controller	/s/John J. Roman John J. Roman

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SIGNATURES (CONT'D)

Date	Title	Signature
______________	Director	______________ John C. Collins
March 13, 1996	Director	/s/Cheryl W. Grisé Cheryl W. Grisé
______________	Director	______________ Gerald Letendre
March 13, 1996	Director	/s/Hugh C. MacKenzie Hugh C. MacKenzie
March 13, 1996	Director	/s/Jane E. Newman Jane E. Newman
March 13, 1996	Director	/s/Robert P. Wax Robert P. Wax

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
(Registrant)

Date: March 13, 1996

By /s/Bernard M. Fox
Bernard M. Fox
Chairman

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 13, 1996	Chairman and a Director	/s/Bernard M. Fox Bernard M. Fox
March 13, 1996	President and a Director	/s/Hugh C. MacKenzie Hugh C. MacKenzie
March 13, 1996	Executive Vice President and Chief Financial Officer	/s/ John H. Forsgren John H. Forsgren
March 13, 1996	Vice President and Controller	/s/John J. Roman John J. Roman

WESTERN MASSACHUSETTS ELECTRIC COMPANY

SIGNATURES (CONT'D)

Date	Title	Signature
March 13, 1996	Director	/s/Robert G. Abair Robert G. Abair
March 13, 1996	Director	/s/Robert E. Busch Robert E. Busch
March 13, 1996	Director	/s/William T. Frain, Jr. William T. Frain, Jr.
March 13, 1996	Director	/s/Cheryl W. Grisé Cheryl W. Grisé
March 13, 1996	Director	/s/John B. Keane John B. Keane

NORTH ATLANTIC ENERGY CORPORATION

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTH ATLANTIC ENERGY CORPORATION
(Registrant)

Date: March 13, 1996

By /s/Bernard M. Fox
Bernard M. Fox
Chairman and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date	Title	Signature
March 13, 1996	Chairman, Chief Executive Officer and a Director	/s/Bernard M. Fox Bernard M. Fox
March 13, 1996	President and a Director	/s/Robert E. Busch Robert E. Busch
March 13, 1996	Executive Vice President and Chief Financial Officer	/s/ John H. Forsgren John H. Forsgren

NORTH ATLANTIC ENERGY CORPORATION

SIGNATURES (CONT'D)

Date	Title	Signature
March 13, 1996	Vice President and Controller	/s/John J. Roman John J. Roman
March 13, 1996	Director	/s/Ted C. Feigenbaum Ted C. Feigenbaum
March 13, 1996	Director	/s/William T. Frain, Jr. William T. Frain, Jr.
March 13, 1996	Director	/s/Cheryl W. Grisé Cheryl W. Grisé
March 13, 1996	Director	/s/John B. Keane John B. Keane
March 13, 1996	Director	/s/Hugh C. MacKenzie Hugh C. MacKenzie

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SCHEDULES

We have audited in accordance with generally accepted auditing standards, the financial statements included in Northeast Utilities' annual report to shareholders and The Connecticut Light and Power Company's, Western Massachusetts Electric Company's, North Atlantic Energy Corporation's, and Public Service Company of New Hampshire's annual reports, incorporated by reference in this Form 10-K, and have issued our reports thereon dated February 16, 1996. Our reports on the financial statements include an explanatory paragraph with respect to the change in method of accounting for property taxes, if applicable to each company, as described in notes to the related company's financial statements. Our audits were made for the purpose of forming an opinion on each company's statements taken as a whole. The schedules listed in the accompanying index are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of each company's basic financial statements. These schedules have been subjected to the auditing procedures applied in the audits of each company's basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to each company's basic financial statements taken as a whole.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
February 16, 1996

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our reports included or incorporated by reference in this Form 10-K, into previously filed Registration Statement No. 33-55279 of The Connecticut Light and Power Company, No. 33-56537 of CL&P Capital, LP, No. 33-51185 of Western Massachusetts Electric Company, and No. 33-34622, No. 33-44814, and No. 33-40156 of Northeast Utilities.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
March 13, 1996

SCHEDULE I
NORTHEAST UTILITIES (PARENT)

FINANCIAL INFORMATION OF REGISTRANT

BALANCE SHEETS

AT DECEMBER 31, 1995 AND 1994

(Thousands of Dollars)

	1995	1994
ASSETS		
Other Property and Investments:		
Investments in subsidiary companies, at equity	$2,701,866	$2,625,228
Investments in transmission companies, at equity	23,557	26,106
Other, at cost	250	636
	2,725,673	2,651,970
Current Assets:		
Cash	18	42
Notes receivable from affiliated companies	9,675	1,975
Receivables from affiliated companies	607	2,598
Prepayments	138	228
	10,438	4,843
Deferred Charges:		
Accumulated deferred income taxes	6,984	7,749
Unamortized debt expense	11	31
Other	122	26
	7,117	7,806
Total Assets	$2,743,228	$2,664,619
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common Shareholders' Equity:		
Common shares, $5 par value--Authorized 225,000,000 shares; 135,611,166 shares issued and 127,050,647 shares outstanding in 1995 and 134,210,226 shares issued and 124,994,322 outstanding in 1994	$ 678,056	$ 671,051
Capital surplus, paid in	936,308	904,371
Deferred benefit plan--employee stock ownership plan	(198,152)	(213,324)
Retained earnings	1,007,340	946,988
Total common shareholders' equity	2,423,552	2,309,086
Long-term debt	210,000	224,000
Total capitalization	2,633,552	2,533,086
Current Liabilities:		
Notes payable to banks	57,500	104,000
Long-term debt and preferred stock--current portion	14,000	12,000
Accounts payable	18,213	962
Accounts payable to affiliated companies	1,074	2,944
Accrued taxes	6,539	7,454
Accrued interest	2,864	3,623
Dividend reinvestment plan	8,995	-
Other	2	17
	109,187	131,000
Other Deferred Credits	489	533
Total Capitalization and Liabilities	$2,743,228	$2,664,619

SCHEDULE I
NORTHEAST UTILITIES (PARENT)

FINANCIAL INFORMATION OF REGISTRANT

STATEMENTS OF INCOME

YEARS ENDED DECEMBER 31, 1995, 1994, AND 1993

(Thousands of Dollars Except Share Information)

	1995	1994	1993
Operating Revenues	$ -	$ -	$ -
Operating Expenses:			
Other	14,267	13,114	2,677
Federal income taxes	(8,585)	(10,736)	(7,564)
Total operating expenses	5,682	2,378	(4,887)
Operating Income (Loss)	(5,682)	(2,378)	4,887
Other Income:			
Equity in earnings of subsidiaries	310,025	309,769	263,725
Equity in earnings of transmission companies	3,561	3,418	3,736
Other, net	329	679	1,302
Other income, net	313,915	313,866	268,763
Income before interest charges	308,233	311,488	273,650
Interest Charges	25,799	24,614	23,697
Earnings for Common Shares	$ 282,434	$ 286,874	$ 249,953
Earnings Per Common Share	$ 2.24	$ 2.30	$ 2.02
Common Shares Outstanding (average)	126,083,645	124,678,192	123,947,631

SCHEDULE I
NORTHEAST UTILITIES (PARENT)
FINANCIAL INFORMATION OF REGISTRANT
STATEMENT OF CASH FLOWS
YEARS ENDED DECEMBER 31, 1995, 1994, 1993
(Thousands of Dollars)

	1995	1994	1993
Operating Activities:			
Net income	$ 282,434	$ 286,874	$ 249,953
Adjustments to reconcile to net cash from operating activities:			
Equity in earnings of subsidiary companies	(310,025)	(309,769)	(263,7[illegible])
Cash dividends received from subsidiary companies	272,350	201,403	191,297
Deferred income taxes	772	(1,890)	(3,199)
Other sources of cash	6,916	3,007	197
Other uses of cash	(528)	(169)	(3,915)
Changes in working capital:			
Receivables	1,991	30,525	(25,012)
Accounts payable	15,381	(43,601)	27,066
Other working capital (excludes cash)	7,396	7,615	(3,010)
Net cash flows from operating activities	276,687	173,995	169,652
Financing Activities:			
Issuance of common shares	47,218	14,551	22,252
Net (decrease) increase in short-term debt	(46,500)	31,500	2,000
Reacquisitions and retirements of long-term debt	(12,000)	(9,000)	(5,000)
Cash dividends on common shares	(221,701)	(219,317)	(218,179)
Net cash flows used for financing activities	(232,983)	(182,266)	(198,927)
Investment Activities:			
NU System Money Pool	(7,700)	17,650	32,975
Investment in subsidiaries	(38,963)	(10,912)	(4,853)
Other investment activities, net	2,935	1,503	1,152
Net cash flows (used for) from investments	(43,728)	8,241	29,274
Net decrease in cash for the period	(24)	(30)	(1)
Cash - beginning of period	42	72	73
Cash - end of period	$ 18	$ 42	$ 72
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 26,430	$ 24,235	$ 23,808
Income taxes (refund)	$ (8,418)	$ (16,786)	$ -

SCHEDULE II

NORTHEAST UTILITIES AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1995
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 16,826	$ 18,010	$ -	$ 20,458 (a)	$ 14,378
Asset valuation reserves	$ 21,585	$ 31,481	$ -	$ -	$ 53,066
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 34,721	$ 11,475	$ -	$ 7,787 (b)	$ 38,409

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

NORTHEAST UTILITIES AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1994
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 14,629	$ 23,194	$ -	$ 20,997 (a)	$ 16,826
Asset valuation reserves	$ 797	$ 29,688	$ -	$ 8,900 (b)	$ 21,585
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 28,286	$ 13,150	$ -	$ 6,715 (c)	$ 34,721

(a) Amounts written off, net of recoveries.
(b) Principally the reduction in the carrying amounts of assets.
(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

NORTHEAST UTILITIES AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1993
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 13,255	$ 21,118	$ -	$ 19,744 (a)	$ 14,629
Asset valuation reserves	$ 17,628	$ 23,169	$ -	$ 40,000 (b)	$ 797
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 24,489	$ 54,583	$ -	$ 50,786 (c)	$ 28,286

(a) Amounts written off, net of recoveries.
(b) Principally the reduction in the carrying amounts of assets.
(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1995
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 12,778	$ 12,722	$ -	$ 14,933 (a)	$ 10,567
Asset valuation reserves	$ 21,585	$ 25,481	$ -	$ -	$ 47,066
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 19,529	$ 5,633	$ -	$ 5,288 (b)	$ 19,874

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1994
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 10,816	$ 17,177	$ -	$ 15,215 (a)	$ 12,778
Asset valuation reserves	$ 797	$ 29,688	$ -	$ 8,900 (b)	$ 21,585
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 14,905	$ 9,924	$ -	$ 5,300 (c)	$ 19,529

(a) Amounts written off, net of recoveries.
(b) Principally the reduction in the carrying amounts of assets.
(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1993
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 8,358	$ 16,366	$ -	$ 13,908 (a)	$ 10,816
Asset valuation reserves	$ 17,628	$ 23,169	$ -	$ 40,000 (b)	$ 797
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 12,665	$ 29,036	$ -	$ 26,796 (c)	$ 14,905

(a) Amounts written off, net of recoveries.
(b) Principally the reduction in the carrying amounts of assets.
(c) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

SCHEDULE II

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1995
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period(a)	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 2,015	$ 2,454	$ -	$ 2,887 (a)	$ 1,582
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 5,113	$ 3,668	$ -	$ 639 (b)	$ 8,142

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

SCHEDULE II

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1994
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 1,816	$ 2,999	$ -	$ 2,800 (a)	$ 2,015
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 3,960	$ 1,525	$ -	$ 372 (b)	$ 5,113

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

SCHEDULE II

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1993
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 2,780	$ 1,771	$ -	$ 2,735 (a)	$ 1,816
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 4,420	$ 457	$ -	$ 917 (b)	$ 3,960

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

SCHEDULE II

WESTERN MASSACHUSETTS ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1995
(Thousands of Dollars)

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 2,032	$ 2,836	$ -	$ 2,638 (a)	$ 2,230
Asset valuation reserves	$ -	$ 6,000	$ -	$ -	$ 6,000
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 4,674	$ 1,340	$ -	$ 870 (b)	$ 5,144

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1994
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 1,997	$ 3,017	$ -	$ 2,982 (a)	$ 2,032
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 3,842	$ 1,473	$ -	$ 641 (b)	$ 4,674

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
YEAR ENDED DECEMBER 31, 1993
(Thousands of Dollars)

SCHEDULE II

Column A	Column B	Column C		Column D	Column E
		Additions			
		(1)	(2)		
Description	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts-describe	Deductions-describe	Balance at end of period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$ 2,117	$ 2,812	$ -	$ 2,932 (a)	$ 1,997
RESERVES NOT APPLIED AGAINST ASSETS:					
Operating reserves	$ 2,543	$ 6,192	$ -	$ 4,893 (b)	$ 3,842

(a) Amounts written off, net of recoveries.
(b) Principally payments for environmental remediation, various injuries and damages, employee medical expenses, and expenses in connection therewith.

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EXHIBIT INDEX

Each document described below is incorporated by reference to the files of the Securities and Exchange Commission, unless the reference to the document is marked as follows:

* - Filed with the 1995 Annual Report on Form 10-K for NU and herein incorporated by reference from the 1995 NU Form 10-K, File No. 1-5324 into the 1995 Annual Reports on Form 10-K for CL&P, PSNH, WMECO and NAEC.

- Filed with the 1995 Annual Report on Form 10-K for NU and herein incorporated by reference from the 1995 NU Form 10-K, File No. 1-5324 into the 1995 Annual Report on Form 10-K for CL&P.

@ - Filed with the 1995 Annual Report on Form 10-K for NU and herein incorporated by reference from the 1995 NU Form 10-K, File No. 1-5324 into the 1995 Annual Report on Form 10-K for PSNH.

** - Filed with the 1995 Annual Report on Form 10-K for NU and herein incorporated by reference from the 1995 NU Form 10-K, File No. 1-5324 into the 1995 Annual Report on Form 10-K for WMECO.

- Filed with the 1995 Annual Report on Form 10-K for NU and herein incorporated by reference from the 1995 Form 10-K, File No. 1-5324 into the 1995 Annual Report on Form 10-K for NAEC.

Exhibit Number	Description
3	Articles of Incorporation and By-Laws
3.1	Northeast Utilities
3.1.1	Declaration of Trust of NU, as amended through May 24, 1988. (Exhibit 3.1.1, 1988 NU Form 10-K, File No. 1-5324)
3.2	The Connecticut Light and Power Company
3.2.1	Certificate of Incorporation of CL&P, restated to March 2, 1994. (Exhibit 3.2.1, 1993 NU Form 10-K, File No. 1-5324)
3.2.2	By-laws of CL&P, as amended to March 1, 1982. (Exhibit 3.2.2, 1993 NU Form 10-K, File No. 1-5324)
3.3	Public Service Company of New Hampshire
3.3.1	Articles of Incorporation, as amended to May 16, 1991. (Exhibit 3.3.1, 1993 NU Form 10-K, File No. 1-5324)

3.3.2 By-laws of PSNH, as amended to November 1, 1993. (Exhibit 3.3.2, 1993 NU Form 10-K, File No. 1-5324)

3.4 Western Massachusetts Electric Company

3.4.1 Articles of Organization of WMECO, restated to February 23, 1995. (Exhibit 3.4.1, 1994 NU Form 10-K, File No. 1-5324)

3.4.2 By-laws of WMECO, as amended to February 13, 1995. (Exhibit 3.4.2, 1994 NU Form 10-K, File No. 1-5324)

3.5 North Atlantic Energy Corporation

3.5.1 Articles of Incorporation of NAEC dated September 20, 1991. (Exhibit 3.5.1, 1993 NU Form 10-K, File No. 1-5324)

3.5.2 Articles of Amendment dated October 16, 1991 and June 2, 1992 to Articles of Incorporation of NAEC. (Exhibit 3.5.2, 1993 NU Form 10-K, File No. 1-5324)

3.5.3 By-laws of NAEC, as amended to November 8, 1993. (Exhibit 3.5.3, 1993 NU Form 10-K, File No. 1-5324)

4 Instruments defining the rights of security holders, including indentures

4.1 Northeast Utilities

4.1.1 Indenture dated as of December 1, 1991 between Northeast Utilities and IBJ Schroder Bank & Trust Company, with respect to the issuance of Debt Securities. (Exhibit 4.1.1, 1991 NU Form 10-K, File No. 1-5324)

4.1.2 First Supplemental Indenture dated as of December 1, 1991 between Northeast Utilities and IBJ Schroder Bank & Trust Company, with respect to the issuance of Series A Notes. (Exhibit 4.1.2, 1991 NU Form 10-K, File No. 1-5324)

4.1.3 Second Supplemental Indenture dated as of March 1, 1992 between Northeast Utilities and IBJ Schroder Bank & Trust Company with respect to the issuance of 8.38% Amortizing Notes. (Exhibit 4.1.3, 1992 NU Form 10-K, File No. 1-5324)

4.1.4 Warrant Agreement dated as of June 5, 1992 between Northeast Utilities and the Service Company. (Exhibit 4.1.4, 1992 NU Form 10-K, File No. 1-5324)

4.1.4.1 Additional Warrant Agent Agreement dated as of June 5, 1992 between Northeast Utilities and State Street Bank and Trust Company. (Exhibit 4.1.4.1, 1992 NU Form 10-K, File No. 1-5324)

4.1.4.2 Exchange and Disbursing Agent Agreement dated as of June 5, 1992 among Northeast Utilities, Public Service Company of New Hampshire and State Street Bank and Trust Company. Exhibit 4.1.4.2, 1992 NU Form 10-K, File No. 1-5324)

4.1.5 Credit Agreements among CL&P, NU, WMECO, NUSCO (as Agent) and 15 Commercial Banks dated December 3, 1992 (364 Day and Three-Year Facilities). (Exhibit C.2.38, 1992 NU Form U5S, File No. 30-246)

4.1.6 Credit Agreements among CL&P, WMECO, NU, Holyoke Water Power Company, RRR, NNECO and NUSCO (as Agent) and 2 commercial banks dated December 3, 1992 (364 Day and Three-Year Facilities). (Exhibit C.2.39, 1992 NU Form U5S, File No. 30-246)

4.2 The Connecticut Light and Power Company

4.2.1 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921. (Composite including all twenty-four amendments to May 1, 1967.) (Exhibit 4.1.1, 1989 NU Form 10-K, File No. 1-5324)

Supplemental Indentures to the Composite May 1, 1921 Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, dated as of:

4.2.2	April 1, 1967.	(Exhibit 4.16, File No. 2-60806)
4.2.3	January 1, 1968.	(Exhibit 4.18, File No. 2-60806)
4.2.4	December 1, 1969.	(Exhibit 4.20, File No. 2-60806)
4.2.5	June 30, 1982.	(Exhibit 4.33, File No. 2-79235)
4.2.6	December 1, 1989.	(Exhibit 4.1.26, 1989 NU Form 10-K, File No. 1-5324)
4.2.7	April 1, 1992.	(Exhibit 4.30, File No. 33-59430)
4.2.8	July 1, 1992.	(Exhibit 4.31, File No. 33-59430)
4.2.9	July 1, 1993.	(Exhibit A.10(b), File No. 70-8249)

4.2.10 July 1, 1993. (Exhibit A.10(b), File No. 70-8249)

4.2.11 December 1, 1993. (Exhibit 4.2.14, 1993 NU Form 10-K, File No. 1-5324)

4.2.12 February 1, 1994. (Exhibit 4.2.15, 1993 NU Form 10-K, File No. 1-5324)

4.2.13 February 1, 1994. (Exhibit 4.2.16, 1993 NU Form 10-K, File No. 1-5324)

4.2.14 June 1, 1994. (Exhibit 4.2.15, 1994 NU Form 10-K, File No. 1-5324)

4.2.15 October 1, 1994. (Exhibit 4.2.16, 1994 NU Form 10-K, File No. 1-5324)

4.2.16 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1986 Series) dated as of December 1, 1986. (Exhibit C.1.47, 1986 NU Form U5S, File No. 30-246)

4.2.16.1 Letter of Credit and Reimbursement Agreement (Pollution Control Bonds, 1986 Series) dated as of August 1, 1994. (Exhibit 1 (Execution Copy), File No. 70-7320)

4.2.17 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds, 1988 Series) dated as of October 1, 1988. (Exhibit C.1.55, 1988 NU Form U5S, File No. 30-246)

4.2.17.1 Letter of Credit (Pollution Control Bonds, 1988 Series) dated October 27, 1988.

4.2.17.2 Reimbursement and Security Agreement (Pollution Control Bonds, 1988 Series) dated as of October 1, 1988.

4.2.18 Financing Agreement between Industrial Development Authority of the State of New Hampshire and CL&P (Pollution Control Bonds) dated as of December 1, 1989. (Exhibit C.1.39, 1989 NU Form U5S, File No. 30-246)

4.2.19 Loan and Trust Agreement among Business Finance Authority of the State of New Hampshire, CL&P and the Trustee (Pollution Control Bonds, 1992 Series A) dated as of December 1, 1992.(Exhibit C.2.33, 1992 NU Form U5S, File No. 30-246)

4.2.19.1 Letter of Credit and Reimbursement Agreement (Pollution Control Bonds, 1992 Series A) dated as of December 1, 1992.

4.2.20 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.21, 1993 NU Form 10-K, File No. 1-5324)

4.2.20.1 Letter of Credit and Reimbursement Agreement (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.23, 1993 NU Form 10-K, File No. 1-5324)

4.2.21 Loan Agreement between Connecticut Development Authority and CL&P (Pollution Control Bonds - Series B, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.22, 1993 NU Form 10-K, File No. 1-5324)

4.2.21.1 Letter of Credit and Reimbursement Agreement (Pollution Control Bonds - Series B, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.2.24, 1993 NU Form 10-K, File No. 1-5324)

4.2.22 Amended and Restated Limited Partnership Agreement (CL&P Capital, L.P.) among CL&P, NUSCO, and the persons who became limited partners of CL&P Capital, L.P. in accordance with the provisions thereof dated as of January 23, 1995 (MIPS). (Exhibit A.1 (Execution Copy), File No. 70-8451)

4.2.23 Indenture between CL&P and Bankers Trust Company, Trustee (Series A Subordinated Debentures), dated as of January 1, 1995 (MIPS). (Exhibit B.1 (Execution Copy), File No. 70-8451)

4.2.24 Payment and Guaranty Agreement of CL&P dated as of January 23, 1995 (MIPS). (Exhibit B.3 (Execution Copy), File No. 70-8451)

4.3 Public Service Company of New Hampshire

4.3.1 First Mortgage Indenture dated as of August 15, 1978 between PSNH and First Fidelity Bank, National Association,New Jersey, Trustee, (Composite including all amendments to May 16, 1991). (Exhibit 4.4.1, 1992 NU Form 10-K, File No. 1-5324)

4.3.1.1 Tenth Supplemental Indenture dated as of May 1, 1991 between PSNH and First Fidelity Bank, National Association. (Exhibit 4.1, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392).

4.3.2 Revolving Credit Agreement dated as of May 1, 1991. (Exhibit 4.12, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.3 Series A (Tax Exempt New Issue) PCRB Loan and Trust Agreement dated as of May 1, 1991. (Exhibit 4.2, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.4 Series B (Tax Exempt Refunding) PCRB Loan and Trust Agreement dated as of May 1, 1991. (Exhibit 4.3, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.5 Series C (Tax Exempt Refunding) PCRB Loan and Trust Agreement dated as of May 1, 1991. (Exhibit 4.4, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.6 Series D (Taxable New Issue) PCRB Loan and Trust Agreement dated as of May 1, 1991. (Exhibit 4.5, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.6.1 First Supplement to Series D (Tax Exempt Refunding Issue) PCRB Loan and Trust Agreement dated as of December 1, 1992. (Exhibit 4.4.5.1, 1992 NU Form 10-K, File No. 1-5324)

4.3.6.2 Second Series D (May 1, 1991 Taxable New Issue and December 1, 1992 Tax Exempt Refunding Issue) PCRB Letter of Credit and Reimbursement Agreement dated as of May 1, 1995 (Exhibit B.4, Execution Copy, File No. 70-8036)

4.3.7 Series E (Taxable New Issue) PCRB Loan and Trust Agreement dated as of May 1, 1991. (Exhibit 4.6, PSNH Current Report on Form 8-K dated February 10, 1992, File No. 1-6392)

4.3.7.1 First Supplement to Series E (Tax Exempt Refunding Issue) PCRB Loan and Trust Agreement dated as of December 1, 1993. (Exhibit 4.3.8.1, 1993 NU Form 10-K, File No. 1-5324)

4.3.7.2 Second Series E (May 1, 1991 Taxable New Issue and December 1, 1993 Tax Exempt Refunding Issue) PCRB Letter of Credit and Reimbursement Agreement dated as of May 1, 1995. (Exhibit B.5, Execution Copy, File No. 70-8036)

4.4 Western Massachusetts Electric Company

4.4.1 First Mortgage Indenture and Deed of Trust between WMECO and Old Colony Trust Company, Trustee, dated as of August 1, 1954. (Exhibit 4.4.1, 1993 NU Form 10-K, File No. 1-5324)

Supplemental Indentures thereto dated as of:

4.4.2 March 1, 1967. (Exhibit 2.5, File No. 2-68808)

4.4.3 September 1, 1990. (Exhibit 4.3.15, 1990 NU Form 10-K, File No. 1-5324.)

4.4.4 December 1, 1992. (Exhibit 4.15, File No. 33-55772)

4.4.5 January 1, 1993. (Exhibit 4.5.13, 1992 NU Form 10-K, File No. 1-5324)

4.4.6 March 1, 1994. (Exhibit 4.4.11, 1993 NU Form 10-K, File No. 1-5324)

4.4.7 March 1, 1994. (Exhibit 4.4.12, 1993 NU Form 10-K, File No. 1-5324)

4.4.8 Loan Agreement between Connecticut Development Authority and WMECO, (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.4.13, 1993 NU Form 10-K, File No. 1-5324)

4.4.8.1 Letter of Credit and Reimbursement Agreement (Pollution Control Bonds - Series A, Tax Exempt Refunding) dated as of September 1, 1993. (Exhibit 4.4.14, 1993 NU Form 10-K, File No. 1-5324)

4.5 North Atlantic Energy Corporation

4.5.1 First Mortgage Indenture and Deed of Trust between NAEC and United States Trust Company of New York, Trustee, dated as of June 1, 1992. (Exhibit 4.6.1, 1992 NU Form 10-K, File No. 1-5324)

4.5.2 Term Credit Agreement dated as of November 9, 1995.

10 Material Contracts

10.1 Stockholder Agreement dated as of July 1, 1964 among the stockholders of Connecticut Yankee Atomic Power Company (CYAPC). (Exhibit 10.1, 1994 NU Form 10-K, File No. 1-5324)

10.2 Form of Power Contract dated as of July 1, 1964 between CYAPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 10.2, 1994 NU Form 10-K, File No. 1-5324)

10.2.1 Form of Additional Power Contract dated as of April 30, 1984, between CYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.2.1, 1994 NU Form 10-K, File No. 1-5324)

10.2.2 Form of 1987 Supplementary Power Contract dated as of April 1, 1987, between CYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.2.6, 1987 NU Form 10-K, File No. 1-5324)

10.3 Capital Funds Agreement dated as of September 1, 1964 between CYAPC and CL&P, HELCO, PSNH and WMECO. (Exhibit 10.3, 1994 NU Form 10-K, File No. 1-5324)

10.4 Stockholder Agreement dated December 10, 1958 between Yankee Atomic Electric Company (YAEC) and CL&P, HELCO, PSNH and WMECO. (Exhibit 10.4, 1993 NU Form 10-K, File No. 1-5324)

10.5 Form of Amendment No. 3, dated as of April 1, 1985, to Power Contract between YAEC and each of CL&P, PSNH and WMECO, including a composite restatement of original Power Contract dated June 30, 1959 and Amendment No. 1 dated April 1, 1975 and Amendment No. 2 dated October 1, 1980. (Exhibit 10.5, 1988 NU Form 10-K, File No. 1-5324.)

10.5.1 Form of Amendment No. 4 to Power Contract, dated May 6, 1988, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.1, 1989 NU Form 10-K, File No. 1-5324)

10.5.2 Form of Amendment No. 5 to Power Contract, dated June 26, 1989, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.2, 1989 NU Form 10-K, File No. 1-5324)

10.5.3 Form of Amendment No. 6 to Power Contract, dated July 1,1989, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.3, 1989 NU Form 10-K, File No. 1-5324)

10.5.4 Form of Amendment No. 7 to Power Contract, dated February 1, 1992, between YAEC and each of CL&P, PSNH and WMECO. (Exhibit 10.5.4, 1993 NU Form 10-K, File No. 1-5324)

10.6 Stockholder Agreement dated as of May 20, 1968 among stockholders of MYAPC. (Exhibit 4.15, File No. 2-30018)

10.7 Form of Power Contract dated as of May 20, 1968 between MYAPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 4.14, File No. 2-30018)

10.7.1 Form of Amendment No. 1 to Power Contract dated as of March 1, 1983 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.1, 1993 NU Form 10-K, File No. 1-5324)

10.7.2 Form of Amendment No. 2 to Power Contract dated as of January 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.2, 1993 NU Form 10-K, File No. 1- 5324)

10.7.3 Form of Amendment No. 3 to Power Contract dated as of October 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit No. 10.7.3, 1994 NU Form 10-K, File No. 1-5324)

10.7.4 Form of Additional Power Contract dated as of February 1, 1984 between MYAPC and each of CL&P, PSNH and WMECO. (Exhibit 10.7.4, 1993 NU Form 10-K, File No. 1-5324)

10.8 Capital Funds Agreement ated as of May 20, 1968 between Maine Yankee Atomic Power Company (MYAPC) and CL&P, PSNH, HELCO and WMECO. (Exhibit 4.13, File No. 2-30018)

10.8.1 Amendment No. 1 to Capital Funds Agreement, dated as of August 1, 1985, between MYAPC, CL&P, PSNH and WMECO. (Exhibit No. 10.8.1, 1994 NU Form 10-K, File No. 1-5324)

10.9 Sponsor Agreement dated as of August 1, 1968 among the sponsors of VYNPC. (Exhibit 4.16, File No. 2-30285)

10.10 Form of Power Contract dated as of February 1, 1968 between VYNPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 4.18, File No. 2-30018)

10.10.1 Form of Amendment to Power Contract dated as of June 1, 1972 between VYNPC and each of CL&P, HELCO, PSNH and WMECO. (Exhibit 5.22, File No. 2-47038)

10.10.2 Form of Second Amendment to Power Contract dated as of April 15, 1983 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.2, 1993 NU Form 10-K, File No. 1-5324)

10.10.3 Form of Third Amendment to Power Contract dated as of April 24, 1985 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit No. 10.10.3, 1994 NU Form 10-K, File No. 1-5324)

10.10.4 Form of Fourth Amendment to Power Contract dated as of June 1, 1985 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.4, 1986 NU Form 10-K, File No. 5324)

10.10.5 Form of Fifth Amendment to Power Contract dated as of May 6, 1988 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.5, 1990 NU Form 10-K, File No. 1-5324)

10.10.6 Form of Sixth Amendment to Power Contract dated as of May 6, 1988 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.6, 1990 NU Form 10-K, File No. 1-5324)

10.10.7 Form of Seventh Amendment to Power Contract dated as of June 15, 1989 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.7, 1990 NU Form 10-K, File No. 1-5324)

10.10.8 Form of Eighth Amendment to Power Contract dated as of December 1, 1989 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.8, 1990 NU Form 10-K, File No. 1-5324)

10.10.9 Form of Additional Power Contract dated as of February 1, 1984 between VYNPC and each of CL&P, PSNH and WMECO. (Exhibit 10.10.9, 1993 NU Form 10-K, File No. 1-5324)

10.11 Capital Funds Agreement dated as of February 1, 1968 between Vermont Yankee Nuclear Power Corporation (VYNPC) and CL&P, HELCO, PSNH and WMECO. (Exhibit 4.16, File No. 2-30018)

10.11.1 Form of First Amendment to Capital Funds Agreement dated as of March 12, 1968 between VYNPC and CL&P, HELCO, PSNH and WMECO. (Exhibit 4.17, File No. 2-30018)

10.11.2 Form of Second Amendment to Capital Funds Agreement dated as of September 1, 1993 between VYNPC and CL&P, HELCO, PSNH and WMECO. (Exhibit 10.11.2, 1993 NU Form 10-K, File No. 1-5324)

10.12 Amended and Restated Millstone Plant Agreement dated as of December 1, 1984 by and among CL&P, WMECO and Northeast Nuclear Energy Company (NNECO). (Exhibit 10.12, 1994 NU Form 10-K, File No. 1-5324)

10.13 Sharing Agreement dated as of September 1, 1973 with respect to 1979 Connecticut nuclear generating unit (Millstone 3). (Exhibit 6.43, File No. 2-50142)

10.13.1 Amendment dated August 1, 1974 to Sharing Agreement - 1979 Connecticut Nuclear Unit. (Exhibit 5.45, File No. 2-52392)

10.13.2 Amendment dated December 15, 1975 to Sharing Agreement - 1979 Connecticut Nuclear Unit. (Exhibit 7.47, File No. 2-60806)

10.13.3 Amendment dated April 1, 1986 to Sharing Agreement - 1979 Connecticut Nuclear Unit. (Exhibit 10.17.3, 1990 NU Form 10-K, File No. 1-5324)

10.14 Agreement dated July 19, 1990, among NAESCO and Seabrook Joint owners with respect to operation of Seabrook. (Exhibit 10.53, 1990 NU Form 10-K, File No. 1-5324)

10.15 Sharing Agreement between CL&P, WMECO, HP&E, HWP and PSNH dated as of June 1, 1992. (Exhibit 10.17, 1992 NU Form 10-K, File No. 1-5324)

10.16 Rate Agreement by and between NUSCO, on behalf of NU, and the Governor of the State of New Hampshire and the New Hampshire Attorney General dated as of November 22, 1989. (Exhibit 10.44, 1989 NU Form 10-K, File No. 1-5324)

* 10.16.1 First Amendment to Rate Agreement dated as of December 5, 1989.

* 10.16.2 Second Amendment to Rate Agreement dated as of December 12, 1989.

* 10.16.3 Third Amendment to Rate Agreement dated as of December 3, 1993.

* 10.16.4 Fourth Amendment to Rate Agreement dated as of September 21, 1994.

* 10.16.5 Fifth Amendment to Rate Agreement dated as of September 9, 1994.

10.17 Form of Seabrook Power Contract between PSNH and NAEC, as amended and restated. (Exhibit 10.45, NU 1992 Form 10-K, File No. 1-5324)

10.18 Agreement (composite) for joint ownership, construction and operation of New Hampshire nuclear unit, as amended through the November 1, 1990 twenty-third amendment. (Exhibit No. 10.17, 1994 NU Form 10-K, File No. 1-5324)

10.18.1 Memorandum of Understanding dated November 7, 1988 between PSNH and Massachusetts Municipal Wholesale Electric Company (Exhibit 10.17, PSNH 1989 Form 10-K, File No. 1-6392)

10.18.2 Agreement of Settlement among Joint Owners dated as of January 13, 1989. (Exhibit 10.13.21, 1988 NU Form 10-K, File No. 1-5324)

10.18.2.1 Supplement to Settlement Agreement, dated as of February 7, 1989, between PSNH and Central Maine Power Company. (Exhibit 10.18.1, PSNH 1989 Form 10-K, File No. 1-6392)

10.19 Amended and Restated Agreement for Seabrook Project Disbursing Agent dated as of November 1, 1990. (Exhibit 10.4.7, File No. 33-35312)

10.19.1 Form of First Amendment to Exhibit 10.19. (Exhibit 10.4.8, File No. 33-35312)

10.19.2 Form (Composite) of Second Amendment to Exhibit 10.19. (Exhibit 10.18.2, 1993 NU Form 10-K, File No. 1-5324)

10.20 Agreement dated November 1, 1974 for Joint Ownership, Construction and Operation of William F. Wyman Unit No. 4 among PSNH, Central Maine Power Company and other utilities. (Exhibit 5.16 , File No. 2-52900)

10.20.1 Amendment to Exhibit 10.20 dated June 30, 1975. (Exhibit 5.48, File No. 2-55458)

10.20.2 Amendment to Exhibit 10.20 dated as of August 16, 1976. (Exhibit 5.19, File No. 2-58251)

10.20.3 Amendment to Exhibit 10.20 dated as of December 31, 1978. (Exhibit 5.10.3, File No. 2-64294)

10.21 Form of Service Contract dated as of July 1, 1966 between each of NU, CL&P and WMECO and the Service Company. (Exhibit 10.20, 1993 NU Form 10-K, File No. 1-5324)

10.21.1 Service Contract dated as of June 5, 1992 between PSNH and the Service Company. (Exhibit 10.12.4, 1992 NU Form 10-K, File No. 1-5324)

10.21.2 Service Contract dated as of June 5, 1992 between NAEC and the Service Company. (Exhibit 10.12.5, 1992 NU Form 10-K, File No. 1-5324)

10.21.3 Form of Annual Renewal of Service Contract. (Exhibit 10.20.3, 1993 NU Form 10-K, File No. 1-5324)

10.22 Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of June 1, 1970 with respect to pooling of generation and transmission. (Exhibit 13.32, File No. 2-38177)

10.22.1 Amendment to Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of February 2, 1982 with respect to pooling of generation and transmission. (Exhibit 10.21.1, 1993 NU Form 10-K, File No. 1-5324)

10.22.2 Amendment to Memorandum of Understanding between CL&P, HELCO, HP&E, HWP and WMECO dated as of January 1, 1984 with respect to pooling of generation and transmission. (Exhibit 10.21.2, 1994 NU Form 10-K, File No. 1-5324)

10.23 New England Power Pool Agreement effective as of November 1, 1971, as amended to November 1, 1988. (Exhibit 10.15, 1988 NU Form 10-K, File No. 1-5324.)

10.23.1 Twenty-sixth Amendment to Exhibit 10.23 dated as of March 15, 1989. (Exhibit 10.15.1, 1990 NU Form 10-K, File No. 1-5324)

10.23.2 Twenty-seventh Amendment to Exhibit 10.23 dated as of October 1, 1990. (Exhibit 10.15.2, 1991 NU Form 10-K, File No. 1-5324)

10.23.3 Twenty-eighth Amendment to Exhibit 10.23 dated as of September 15, 1992. (Exhibit 10.18.3, 1992 NU Form 10-K, File No. 1-5324)

10.23.4 Twenty-ninth Amendment to Exhibit 10.23 dated as of May 1, 1993. (Exhibit 10.22.4, 1993 NU Form 10-K, File No. 1-5324)

* 10.23.5 Thirty-second Amendment (Amendments 30 and 31 were withdrawn) to Exhibit 10.23 dated as of September 1, 1995.

10.24 Agreements among New England Utilities with respect to the Hydro-Quebec interconnection projects. (See Exhibits 10(u) and 10(v); 10(w), 10(x), and 10(y), 1990 and 1988, respectively, Form 10-K of New England Electric System, File No. 1-3446.)

10.25 Trust Agreement dated February 11, 1992, between State Street Bank and Trust Company of Connecticut, as Trustor, and Bankers Trust Company, as Trustee, and CL&P and WMECO, with respect to NBFT. (Exhibit 10.23, 1991 NU Form 10-K, File No. 1-5324)

10.25.1 Nuclear Fuel Lease Agreement dated as of February 11, 1992, between Bankers Trust Company, Trustee, as Lessor, and CL&P and WMECO, as Lessees. (Exhibit 10.23.1, 1991 NU Form 10-K, File No. 1-5324)

10.26 Simulator Financing Lease Agreement, dated as of February 1, 1985, by and between ComPlan and NNECO. (Exhibit 10.25, 1994 NU Form 10-K, File No. 1-5324)

10.27 Simulator Financing Lease Agreement, dated as of May 2, 1985, by and between The Prudential Insurance Company of America and NNECO. (Exhibit No. 10.26, 1994 NU Form 10-K, File No. 1-5324)

10.28 Lease dated as of April 14, 1992 between The Rocky River Realty Company (RRR) and Northeast Utilities Service Company (NUSCO) with respect to the Berlin, Connecticut headquarters (office lease). (Exhibit 10.29, 1992 NU Form 10-K, File No. 1-5324)

10.28.1 Lease dated as of April 14, 1992 between RRR and NUSCO with respect to the Berlin, Connecticut headquarters (project lease). (Exhibit 10.29.1, 1992 NU Form 10-K, File No. 1-5324)

10.29 Millstone Technical Building Note Agreement dated as of December 21, 1993 between, by and between The Prudential Insurance Company of America and NNECO. (Exhibit 10.28, 1993 NU Form 10-K, File No. 1-5324)

10.30 Lease and Agreement, dated as of December 15, 1988, by and between WMECO and Bank of New England, N.A., with BNE Realty Leasing Corporation of North Carolina. (Exhibit 10.63, 1988 NU Form 10-K, File No. 1-5324.)

10.31 Note Agreement dated April 14, 1992, by and between The Rocky River Realty Company (RRR) and Purchasers named therein (Connecticut General Life Insurance Company, Life Insurance Company of North America, INA Life Insurance Company of New York, Life Insurance Company of Georgia), with respect to RRR's sale of $15 million of guaranteed senior secured notes due 2007 and $28 million of guaranteed senior secured notes due 2017. (Exhibit 10.52, 1992 NU Form 10-K, File No. 1-5324)

10.31.1 Note Guaranty dated April 14, 1992 by Northeast Utilities pursuant to Note Agreement dated April 14, 1992 between RRR and Note Purchasers, for the benefit of The Connecticut National Bank as Trustee, the Purchasers and the owners of the notes. (Exhibit 10.52.1, 1992 NU Form 10-K, File No. 1-5324)

10.31.2 Assignment of Leases, Rents and Profits, Security Agreement and Negative Pledge, dated as of April 14, 1992 among RRR, NUSCO and The Connecticut National Bank as Trustee, securing notes sold by RRR pursuant to April 14, 1992 Note Agreement. (Exhibit 10.52.2, 1992 NU Form 10-K, File No. 1-5324)

10.32 Master Trust Agreement dated as of September 2, 1986 between CL&P and WMECO and Colonial Bank as Trustee, with respect to reserve funds for Millstone 1 decommissioning costs. (Exhibit 10.80, 1986 NU Form 10-K, File No. 1-5324)

10.32.1 Notice of Appointment of Mellon Bank, N.A. as Successor Trustee, dated November 20, 1990, and Acceptance of Appointment. (Exhibit 10.41.1, 1992 NU Form 10-K, File No. 1-5324)

10.33 Master Trust Agreement dated as of September 2, 1986 between CL&P and WMECO and Colonial Bank as Trustee, with respect to reserve funds for Millstone 2 decommissioning costs. (Exhibit 10.81, 1986 NU Form 10-K, File No. 1-5324)

10.33.1 Notice of Appointment of Mellon Bank, N.A. as Successor Trustee, dated November 20, 1990, and Acceptance of Appointment. (Exhibit 10.42.1, 1992 NU Form 10-K, File No. 1-5324)

10.34 Master Trust Agreement dated as of April 23, 1986 between CL&P and WMECO and Colonial Bank as Trustee, with respect to reserve funds for Millstone 3 decommissioning costs. (Exhibit 10.82, 1986 NU Form 10-K, File No. 1-5324)

10.34.1 Notice of Appointment of Mellon Bank, N.A. as Successor Trustee, dated November 20, 1990, and Acceptance of Appointment. (Exhibit 10.43.1, 1992 NU Form 10-K, File No. 1-5324)

10.35 NU Executive Incentive Plan, effective as of January 1, 1991. (Exhibit 10.44, NU 1991 Form 10-K, File No. 1-5324)

10.36 Supplemental Executive Retirement Plan for Officers of NU System Companies, Amended and Restated effective as of January 1, 1992. (Exhibit 10.45.1, NU Form 10-Q for the Quarter Ended June 30, 1992, File No. 1-5324)

10.36.1 Amendment 1 to Exhibit 10.36, effective as of August 1, 1993. (Exhibit 10.35.1, 1993 NU Form 10-K, File No. 1-5324)

10.36.2 Amendment 2 to Exhibit 10.36, effective as of January 1, 1994. (Exhibit 10.35.2, 1993 NU Form 10-K, File No. 1-5324)

* 10.36.3 Amendment 3 to Exhibit 10.36, effective as of January 1, 1996.

10.37 Loan Agreement dated as of December 2, 1991, by and between NU and Mellon Bank, N.A., as Trustee, with respect to NU's loan of $175 million to an ESOP Trust. (Exhibit 10.46, NU 1991 Form 10-K, File No. 1-5324)

10.37.1 First Amendment to Exhibit 10.37 dated February 7, 1992. (Exhibit 10.36.1, 1993 NU Form 10-K, File No. 1-5324)

10.37.2 Loan Agreement dated as of March 19, 1992 by and between NU and Mellon Bank, N.A., as Trustee, with respect to NU's loan of $75 million to the ESOP Trust. (Exhibit 10.49.1, 1992 NU Form 10-K, File No. 1-5324)

10.37.3 Second Amendment to Exhibit 10.37 dated April 9, 1992. (Exhibit 10.36.3, 1993 NU Form 10-K, File No. 1-5324)

10.38 Employment Agreement. (Exhibit 10.48, NU Form 10-Q for the Quarter Ended June 30, 1992, File No. 1-5324)

* 10.39 Northeast Utilities Deferred Compensation Plan for Trustees, Amended and Restated December 13, 1994.

* 10.40 Deferred Compensation Plan for Officers of Northeast Utilities System Companies adopted September 23, 1986.

* 10.41 Reciprocal Support Agreement Among NNECO, NAESCO, CYAPC, YAEC and NUSCO dated January 1, 1996.

13 Annual Report to Security Holders (Each of the Annual Reports is filed only with the Form 10-K of that respective registrant.)

* 13.1 Portions of the Annual Report to Shareholders of NU (pages 15-46) that have been incorporated by reference into this Form 10-K.

13.2 Annual Report of CL&P.

13.3 Annual Report of WMECO.

13.4 Annual Report of PSNH.

13.5 Annual Report of NAEC.

*21 Subsidiaries of the Registrant.

27 Financial Data Schedules (Each Financial Data Schedule is filed only with the Form 10-K of that respective registrant.)

27.1 Financial Data Schedule of NU.

27.2 Financial Data Schedule of CL&P.

27.3 Financial Data Schedule of WMECO.

27.4 Financial Data Schedule of PSNH.

27.5 Financial Data Schedule of NAEC.