10CFR50.71(b)
10CFR140.15(b)(1)

BOSTON EDISON
Pilgrim Nuclear Power Station
600 Rocky Hill Road
Plymouth, Massachusetts 02360

April 10, 1995
BECo Ltr. #95-042

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Docket No. 50-293
License No. DPR-35

Annual Financial Statement for 1994

In accordance with 10CFR 50.71(b) and 10CFR 140.15(b)(1), Boston Edison submits the enclosed 1994 Annual Report, and the Securities and Exchange Commission (SEC) Form 10-K which corresponds to the 1994 Annual Report.

If you have any questions on this documentation, please contact Mr. Gerald Whitney at (508) 830-7872.

Respectfully,

R. V. Fairbank
Manager, Regulatory
Affairs and Emergency
Preparedness Department

GGW/Rap95/10K-94

Attachment

cc: Mr. R. Eaton, Project Manager
Division of Reactor Projects - I/II
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1 White Flint North
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Senior Resident Inspector
Pilgrim Nuclear Power Station

M004

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 [FEE REQUIRED]

For the fiscal year ended December 31, 1994

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 1-2301

BOSTON EDISON COMPANY

(Exact name of registrant as specified in its charter)

Massachusetts	**04-1278810**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
800 Boylston Street, Boston, Massachusetts	**02199**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 617-424-2000

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

Title of each class	Name of each exchange on which registered
Common stock, par value $1 per share	New York Stock Exchange Boston Stock Exchange
Cumulative preferred stock:	
7.75% Series, par value $100 per share (represented by depositary shares-each represents one-fourth interest in par value)	New York Stock Exchange
8.25% Series, par value $100 per share (represented by depositary shares-each represents one-fourth interest in par value)	New York Stock Exchange

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

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 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. [ ]

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 X NO __

The aggregate market value of the voting stock held by non-affiliates of the registrant as of February 28, 1995 computed by reference to the last reported sale price of the common stock, $1 par value, of the registrant of the New York Stock Exchange composite tape on that date: $1,117,923,951.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 28, 1995
Common Stock, $1 par value	45,629,549 shares

DOCUMENTS INCORPORATED BY REFERENCE

Part	Document
III	Portions of definitive proxy statement dated March 27, 1995 for Annual Meeting of Stockholders to be held May 12, 1995.

Boston Edison Company

Form 10-K Annual Report

December 31, 1994

Part I

Item 1. Business

(a) General Development of Business

Boston Edison Company (the Company) is an investor-owned regulated public utility incorporated in 1886 under Massachusetts law. The Company operates in the energy and energy services business, which includes the generation, purchase, transmission, distribution and sale of electric energy and the development and implementation of demand side management (DSM) programs.

In 1993 the Company established an unregulated subsidiary, Boston Energy Technology Group (BETG), following approval from the Massachusetts Department of Public Utilities (DPU). The Company has authority to invest up to $45 million in this wholly-owned subsidiary. BETG engages in demand side management activities and businesses involving electric transportation and the related infrastructure through its two wholly-owned subsidiaries. In 1994 BETG acquired a substantial majority interest in two additional businesses. REZ-TEK International Corporation produces systems that treat cooling water used in commercial and industrial air conditioning systems in an energy efficient and environmentally sound manner, and Conecc Corporation provides engineering and project management services to energy and water conservation project developers and contractors. The Company does not currently have a substantial investment in BETG and does not expect the subsidiary to significantly impact the results of operations in the next several years.

(b) Financial Information about Industry Segments

The Company operates primarily as a regulated electric public utility, therefore industry segment information is not applicable.

(c) Narrative Description of Business

Principal Products and Services

The Company supplies electricity at retail to an area of 590 square miles encompassing the City of Boston and 39 surrounding cities and towns. The population of the area served with electricity at retail is approximately 1.5 million. In 1994 the Company served an average of 656,000 customers. The Company also supplies electricity at wholesale for resale to other utilities and municipal electric departments. Revenues by class for the last three years consisted of the following:

	1994	1993	1992
Retail electric revenues:			
Commercial	50%	49%	48%
Residential	28%	28%	27%
Industrial	9%	10%	10%
Other	2%	1%	2%
Wholesale and contract revenues	11%	12%	13%

Sources and Availability of Fuel

The Company owns two stations whose generating units are fueled by oil, natural gas or both, one nuclear power station and ten combustion turbine generators. See the *Company-Owned Facilities* section of Item 2. The Company's generation by type of fuel and the cost of fuel for each of the last five years were as follows:

	Percentage of Company Generation by Source (%)					Average Cost of Fuel ($ per Million BTU)				
	1994	1993	1992	1991	1990	1994	1993	1992	1991	1990
Oil	27.8	31.3	33.7	42.8	33.6	2.35	2.38	2.40	2.60	2.76
Gas	31.6	24.3	25.7	24.9	33.3	2.28	2.67	2.55	2.08	2.35
Nuclear	40.6	44.4	40.6	32.3	33.1	0.50	0.51	0.52	0.56	0.59

The majority of the Company's residual oil purchases consists of imported oil acquired primarily from international suppliers. The Company has contracts with major oil companies that can supply most of its estimated requirements, assuming no major disruptions in oil producing regions. Within contract provisions, the Company has the ability to purchase significant amounts of oil in the spot market when it is economical to do so.

Most of the Company's natural gas is supplied on an interruptible basis by contract. These contracts permit interruptions in deliveries by the supplier when natural gas pipeline capacity is unavailable. Deliveries of natural gas to the Company's generating units from suppliers may also be dependent on the availability of pipeline capacity to the New England region and competitive forces prevailing in the pipeline industry. Beginning in April 1995 the Company will be required to operate New Boston Station using exclusively natural gas as fuel, except in certain emergency circumstances, as part of a 1991 consent order with the Massachusetts Department of Environmental Protection (DEP). The Company has made arrangements for a firm supply of natural gas to run the station at a minimum level and is developing a least-cost plan for operation beyond this minimum level involving principally the utilization of interruptible gas supplies or short-term capacity purchases.

In order to obtain nuclear fuel for use at Pilgrim Station the Company must obtain supplies of uranium concentrates and secure contracts for these concentrates to go through the processes of conversion, enrichment and fabrication of nuclear fuel assemblies. The Company currently has contracts for supplies of uranium concentrates and the processes of conversion, enrichment and fabrication through 1998, 2000, 1998 and 2012, respectively.

Franchises

Through its charter, which is unlimited in time, the Company has the right to engage in the business of producing and selling electricity, steam and other forms of energy, has powers incidental thereto and is entitled to all the rights and privileges of and subject to the duties imposed upon electric companies under Massachusetts laws. The locations in public ways for the Company's electric transmission and distribution lines are obtained from municipal and other state authorities which, in granting these locations, act as agents for the state. In some cases the action of these authorities is subject to appeal to the DPU. The rights to these locations are not limited in time, but are not vested and are subject to the action of these authorities and the legislature.

Seasonal Nature of Business

The Company's kWh sales and revenues are typically higher in the winter and summer than in spring and fall as sales tend to vary with weather conditions. In addition, the Company bills higher base rates to commercial and industrial customers during the billing months of June through September as mandated by the DPU. Accordingly, a significant portion of annual earnings occurs in the Company's third quarter. See Selected Consolidated Quarterly Financial Data (Unaudited) in Item 8.

Working Capital Practices

The Company has no special practices with respect to working capital that would be considered unusual for the electric utility industry or significant for the understanding of the Company's business.

Customer Dependence

No material portion of the Company's business is dependent upon one or a few customers.

Government Contracts

No material portion of the Company's business is subject to renegotiation or termination of government contracts or subcontracts.

Competitive Conditions

The Company is operating in an increasingly competitive environment. The electric utility business is in a period of transition from a traditional rate-regulated environment based on cost recovery to an environment with both competition and modified regulation. The effects of competition to date have been most evident in the wholesale electric market. In response to increased competition from other electric utilities and non-utility generators to sell electricity for resale, the Company has secured long-term power supply agreements with its five wholesale customers. These agreements set the Company's rates through the year 2002 and beyond.

Direct competition with other electric utilities and other energy suppliers for retail electricity sales is still subject to substantial limitations, but there is potential for these limitations to be reduced in the future. The Company and other Massachusetts electric utilities are currently protected in several ways by the DPU and municipal statutes against other utilities offering service to retail customers in their service areas. Another electric utility may not extend its service area to include municipalities other than those named in its agreement of association or charter without DPU authorization granted after notice and public hearing. Also, another company may not obtain an initial location for its lines in a municipality served by the Company without the approval of municipal authorities, subject to the right of appeal to the DPU. Additionally, a municipality may not engage in the electric utility business without complying with statutes requiring specific city or town approval and the purchase of Company property within municipality limits.

However, the Company is currently experiencing some forms of competition in the retail electric market. Current legislation allows industrial and large commercial customers to own and operate their own electric generating units. Retail customers may also substitute natural gas or oil for electricity as fuel for heating and cooling purposes. Large facilities may factor the cost of electricity into their decisions to relocate into or out of a given service territory. In addition, the DPU is currently investigating the benefits of restructuring the electric utility industry in Massachusetts and encouraging utilities to devise and propose incentive ratemaking plans. The Company is responding to the current and anticipated retail competitive challenges in several ways. These include actively participating in the formulation of regulatory policy concerning potential stranded investments, planning to not seek additional base rate increases for at least five years, continuing aggressive control of costs and increasing operating efficiencies.

Research Activities

The Company actively participates in several industry-sponsored research activities. These expenditures, included in other operations and maintenance expense on the consolidated income statement in Item 8, were not material in 1994.

Environmental Matters

The Company is subject to numerous federal, state and local standards with respect to the management of wastes, air and water quality and other environmental considerations. These standards can require modification of existing facilities or curtailment or termination of operations at these facilities, delay or discontinue construction of new facilities and increase capital and operating costs by substantial amounts. Noncompliance with certain standards can, in some cases, also result in the imposition of monetary civil penalties. The Company believes that its operating facilities are in substantial compliance with currently applicable statutory and regulatory environmental requirements.

The Company's capital expenditures for environmental purposes during the five years 1990 through 1994 totalled approximately $137 million. Environmental-related capital expenditures for the years 1995 through 1999 are currently expected to total approximately $47 million, including $11 million in both 1995 and 1996. These amounts exclude costs associated with asbestos removal which totalled approximately $8 million during the five years 1990 through 1994 and are currently expected to total approximately $3 million for the years 1995 through 1999. The Company's capital expenditures for environmental purposes through 1994 included approximately $80 million related to certain improvements in the emission control systems at New Boston Station as discussed in the *Environmental* section of Other Matters in Item 7. Substantial additional expenditures could be required as changes in environmental requirements occur.

The Company is required to clean up 48 properties that it owns or operates in which hazardous materials were released in the past. In addition, the Company has exposure to potential joint and several liability for the cleanup of ten multi-party hazardous waste sites where it is alleged to have generated, transported or disposed of hazardous waste at the sites. Complex litigation or negotiations among the parties and with regulatory authorities is in process concerning the scope and cost of cleanup and the sharing of costs among the potentially responsible parties for several of these sites. The Company's potential hazardous waste liabilities are described further in the *Environmental* section of Item 7.

Spent nuclear fuel and low-level radioactive waste (LLW) result from the operations of Pilgrim Station. Uncertainties currently exist regarding the ultimate disposal of both the spent nuclear fuel and LLW. See Note D to the consolidated financial statements in Item 8 for further discussion regarding spent nuclear fuel and LLW.

As a facility which treats and stores hazardous wastes, Pilgrim Station is required to be licensed by the United States Environmental Protection Agency (EPA). Pilgrim has received interim status approval for the treatment and storage of certain wastes that are both hazardous and radioactive.

The Company is subject to regulation by the EPA and the DEP relative to emissions from its fossil-fired generating units under federal and Massachusetts clean air laws, including the 1990 Clean Air Act Amendments. These regulations require the installation of various emissions controls and, in certain cases, the use of low sulfur content fuels. The Company's current status regarding compliance with DEP regulations and the 1990 Clean Air Act Amendments is discussed in the *Environmental* section of Item 7.

The Company also subject to regulation by the EPA and the DEP with respect to discharges of effluent from its generating stations into receiving waters. The federal Clean Water Act and the Massachusetts Clean Waters Act require the Company to receive permits that limit discharges in accordance with applicable water quality standards and are subject to renewal every five years. The Company has received the required discharge permits for each of its electric generating stations.

There are public concerns regarding electromagnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. These concerns include the possibility of adverse health effects as well as perceived effects on property values. Refer to the *Environmental* section of Item 7 for a discussion of the EMF issue.

Number of Employees

The Company had 4,026 full-time and 25 part-time utility employees as of the end of 1994, 2,560 of which are represented by two locals of the Utility Workers Union of America, AFL-CIO. In 1994 the Company and the locals signed new six-year labor contracts. BETG had 46 full-time employees at the end of 1994.

(d) Financial Information about Foreign and Domestic Operations and Export Sales

See *Principal Products and Services* for information regarding the geographical area served by the Company and revenues by class for the last three years.

(e) Additional Information

Regulation

The Company and its wholly-owned subsidiary, Harbor Electric Energy Company (HEEC), operate primarily under the authority of the DPU, whose jurisdiction includes supervision over retail rates for electricity, financing, investing and accounting. In addition, the Federal Energy Regulatory Commission has jurisdiction over various phases of the Company's business including rates for power sold at wholesale for resale, facilities used for the transmission or sale of such power, certain issuances of short-term debt and regulation of the system of accounts. The Company's subsidiary BETG and its subsidiaries are not subject to such regulation.

The Company is required to submit to the DPU annual performance standards applicable to its generating units and other units from which the Company purchases power through long-term contracts. Under this generating unit performance program, the Company provides quarterly progress reports to the DPU. The DPU has the right to reduce subsequent fuel and purchased power billings if it finds that the Company has been unreasonable or imprudent in the operation of its generating units or in the procurement of fuel. The Company has not yet received orders from the DPU for the performance years ended October 1993 and October 1994. The Company believes that its current provision for refunds is sufficient to cover potential refunds.

The Nuclear Regulatory Commission (NRC) has broad jurisdiction over the siting, construction and operation of nuclear reactors with respect to public health and safety, environmental matters and antitrust considerations. A license granted by the NRC may be revoked, suspended or modified for failure to construct or operate a facility in accordance with its terms. The Company currently holds an operating license for Pilgrim Station which was issued in 1972 and expires in 2012.

Continuing NRC review of existing regulations and certain operating occurrences at other nuclear plants have periodically resulted in the imposition of additional requirements for all domestic nuclear plants, including Pilgrim Station. NRC inspections and investigations can result in the issuance of notices of violation. These notices can also be accompanied by orders directing that certain actions be taken or by the imposition of monetary civil penalties. In addition, the Company could undertake certain actions regarding Pilgrim Station at the request or suggestion of its insurers or the Institute of Nuclear Power Operations (INPO), a voluntary association of nuclear utilities dedicated to the promotion of safety and reliability in the operation of nuclear power plants.

Nuclear power continues to be a subject of political controversy and public debate manifested from time to time in the form of requests for various kinds of federal, state and local legislative or regulatory action, direct voter initiatives or referenda or litigation. The Company cannot predict the extent, cost or timing of any modifications to Pilgrim Station which could be necessary in the future as a result of additional regulatory or other requirements nor can it determine the effect of such future requirements on the continued operation of Pilgrim Station. The Company continues to evaluate the operation of the station from the standpoint of safety, reliability and economics and believes that such continued operation is in the best interests of the Company and its customers.

Capital Expenditures and Financings

The Company's most recent estimates of capital expenditures, allowance for funds used during construction (AFUDC), long-term debt maturities and sinking fund requirements for the years 1995 through 1999 are as follows:

(in thousands)	1995	1996	1997	1998	1999
Plant expenditures	$200,000	$172,000	$172,000	$159,000	$156,000
Nuclear fuel expenditures	11,000	18,000	13,000	24,000	13,000
AFUDC (1)	6,000	5,000	4,000	5,000	4,000
Long-term debt	100,600	101,600	101,600	101,600	1,600
Preferred stock sinking fund	2,000	2,000	2,000	2,000	2,000

(1) Excludes estimated AFUDC on nuclear fuel of approximately $1,000 per year. The estimated AFUDC rate varies from 5.0% to 6.5%.

The Company conducts a continuing review of its capital expenditure and financing programs. These programs and the estimates shown above are therefore subject to revision due to changes in regulatory requirements, environmental standards, availability and cost of capital, interest rates and other assumptions. In addition, depending upon the outcome of certain DEP air quality modeling studies currently in progress, the Company could be required to make additional expenditures by 1999 in order to comply with the provisions of the 1990 Clean Air Act Amendments. The extent of any additional expenditures is uncertain at this time.

Plant expenditures in 1994 were approximately $199 million consisting primarily of additions to the Company's distribution system and fossil and nuclear generation facilities. Significant projects included spending of approximately $13 million for the replacement of electric system property, $10.5 million for a new energy control center, $10 million for a new substation and $9 million for the replacement of the main turbine low pressure rotors at Pilgrim Station.

The Company spent approximately $58 million on its DSM programs in 1994, of which $37 million was capitalized and is being collected from customers over six years. DSM expenditures for 1995 are currently estimated to be approximately $43 million. Beginning in 1995 all costs will be collected primarily in the year incurred in accordance with an order from the DPU.

In 1994 the DPU approved the Company's financing plan to issue up to $500 million of securities through 1996 and to use the proceeds to refinance short and long-term securities and for capital expenditures. See Note H to the consolidated financial statements in Item 8 for specific information relating to the Company's financing activities.

Item 2. Properties and Power Supply

Company-Owned Facilities

The Company's total electric generation capacity as of December 31, 1994 consisted of the following:

Unit	Location	Maximum Capacity (MW)	Type	Year Installed
Pilgrim Nuclear Power Station	Plymouth, Mass.	669	Nuclear	1972
New Boston Station Units 1 and 2	South Boston, Mass.	760	Fossil	1965-1967
Mystic Station	Everett, Mass.			
Units 4-5-6		399	Fossil	1957-1961
Unit 7		592	Fossil	1975
Combustion turbine generators (ten)	Various	302	Fossil	1966-1971

All of the Company's steam fossil fuel-fired generating units are located at tide water and have access to fuel oil storage and/or natural gas or oil pipelines from nearby suppliers.

The Company is also a 5.888% joint owner in W.F. Wyman Unit 4. The 619 MW oil-fired unit located in Yarmouth, Maine began operations in 1978 and is operated by Central Maine Power Company.

Additional electric generation capacity is available to the Company through its contractual arrangements with other utilities and non-utilities and its participation in the New England Power Pool as further described in this item.

The Company's significant items of property consist of electric generating stations, substations and certain service centers and are generally located on Company-owned land. The Company's high-tension transmission lines are generally located on land either owned by the Company or subject to easements in its favor. The Company's low-tension distribution lines and fossil fuel pipelines are located principally on public property under permission granted by municipal and other state authorities.

As of December 31, 1994 the Company's transmission system consisted of 362 miles of overhead circuits operating at 115, 230 and 345 kV and 156 miles of underground circuits operating at 115 and 345 kV. The substations supported by these lines are 44 transmission or combined transmission and distribution substations with transformer capacity of 10,112 megavolt amperes (MVA), 70 distribution substations with transformer capacity of 1,213 MVA and 18 primary network units with 88 MVA capacity. In addition, high tension service was delivered to 231 customers' substations. The overhead and underground distribution systems cover 4,652 and 892 miles of streets, respectively. HEEC, the Company's regulated subsidiary, has a distribution system that consists principally of a 4.1 mile 115kV submarine distribution line and a substation which is located on Deer Island in Boston, Massachusetts.

The Massachusetts Energy Facilities Siting Board (EFSB) must approve Company plans for the construction of certain new generation or transmission facilities based upon findings that such facilities are consistent with state public health, environmental protection and resource use and development policies. The Company currently has no proceedings before the EFSB.

Long-Term Power Contracts

Refer to Note L to the consolidated financial statements in Item 8 for further information regarding the following contracts. The Company also has short-term agreements with several other utilities for varying periods for purchases of system and unit power, for sales of Company system and unit power and for transmission services.

<u>Utility Purchase Contracts</u>:

The Company has a long-term contract with a subsidiary of Commonwealth Energy System in which it receives 25% of the output of an oil-fired electric generating plant. The Company is obligated to pay 25% of the unit's fixed and operating costs plus an annual return on investment.

The Company has two long-term purchased power contracts with the Massachusetts Bay Transportation Authority (MBTA) for the availability of two of the MBTA's jet turbines. The MBTA retains the right to utilize the jets for its own emergency use and for testing purposes while the Company retains New England Power Pool credit for their capacity and output.

The Company owns 9.5% of the common stock of Connecticut Yankee Atomic Power Company, which operates a nuclear generating unit. The Company is entitled to receive 9.5% of the unit's output and is obligated to pay Connecticut Yankee 9.5% of its fixed and operating costs plus an annual return on investment.

Non-Utility Generator Purchase Contracts:

The Company currently purchases 535 MW of capacity and associated energy from non-utility generators. These purchases are from Ocean State Power, Northeast Energy Associates, L'Energia and MassPower. In addition, the Company purchases power from two small hydro facilities.

In March 1995 the Company received a decision from the Massachusetts Supreme Judicial Court (SJC) regarding the Company's appeal of a 1994 DPU order that reaffirmed a 1993 order requiring it to purchase power from an independent power producer (see *Resource regulation* in Item 7). The SJC decision reversed the DPU order and remanded the case to the department for further consideration of evidence.

Sales Contracts:

The Company has agreements with Commonwealth Electric Company, a subsidiary of Commonwealth Energy System, and with Montaup Electric Company, a subsidiary of Eastern Utilities Associates, under which Commonwealth and Montaup each purchase 11% of the capacity and corresponding energy of Pilgrim Station and pay 11% of the unit's fixed and operating costs plus an annual return on investment. Commonwealth and Montaup have also agreed to indemnify the Company to the extent of 11% each of all losses, liability or damage not covered by insurance resulting from the operation, condemnation, shutdown or retirement of the unit. In addition, the Company has similar agreements with multiple municipal electric companies for a total of 3.7% of the capacity and corresponding energy of Pilgrim Station.

New England Power Pool

The Company is a member of the New England Power Pool (NEPOOL), a voluntary association of electric utilities in New England responsible for the coordination, monitoring and directing of the operations of the major generating and transmission facilities in the region. To obtain maximum benefits of power pooling, the electric facilities of all member companies are operated by NEPOOL as if they were a single power system. This is accomplished through the use of a central dispatching system that uses the lowest cost generation and transmission equipment available at any given time. This operation is the responsibility of NEPOOL's central dispatch center, the New England Power Exchange (NEPEX). As a result of its participation in NEPOOL, the Company's operating revenues and costs are affected to some extent by the operations of the other members. The dispatching of Company-owned generating facilities by NEPEX may be affected by minimally increasing energy requirements and any additions to New England generation capacity.

The table below sets forth certain information as of the date of the Company's 1994-1995 winter and 1994 summer peak loads:

	February 6, 1995 (winter 1994-95)	July 21, 1994 (summer 1994)
NEPEX utilities installed capacity:		
Seasonal maximum rating	25,645 MW	24,602 MW
Seasonal normal rating	25,299 MW	24,379 MW
NEPEX peak load (estimate)	19,205 MW	20,519 MW
Company territory peak load	2,473 MW	2,798 MW

The Company's net capacity was 3,561 MW at its winter peak and 3,484 MW at its summer peak. Its corresponding NEPOOL capacity obligations were estimated to be 3,379 MW and 3,306 MW, respectively.

NEPOOL participants have two agreements with Hydro-Quebec of Canada for hydro-electric power. The first agreement, Phase I, provides up to three million MWH of hydro-electric power to NEPOOL annually through 1997. The second agreement, Phase II, is a firm contract that provides seven million MWH of hydro-electric power annually through 2001. The price of the Phase II energy is based on the average cost of fossil fuel in New England for the previous year. The contract price is 80% of that average through 1996 and will be 95% of that average in 1997-2001. The Company receives capacity credit through NEPOOL for approximately 11% of the generation equivalent of the total Hydro-Quebec interconnection.

The Company has an approximately 11% equity ownership interest in the two companies which own and operate the Phase II facilities. All equity participants are required to guarantee, in addition to their own share, the total obligations of those participants who do not meet certain credit criteria. Amounts so guaranteed by the Company were approximately $21 million at December 31, 1994.

Item 3. Legal Proceedings

In 1991 the Company was named in a lawsuit brought in the United States District Court for the District of Massachusetts alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by the Company's 1988 reduction in force. Legal counsel continues to vigorously defend this case. Based on the information presently available the Company does not expect that this litigation or certain other legal matters in which it is currently involved will have a material impact on financial condition. However, an unfavorable decision ordered against the Company could have a material impact on the results of a reporting period.

See also *Environmental Matters* in Item 1 for a discussion of legal issues involving hazardous waste sites.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 1994.

Executive Officers of the Registrant

The names, ages, positions and business experience during the last five years of all the executive officers of Boston Edison Company and its subsidiaries as of March 1, 1995 are listed below. There are no family relationships between any of the officers of the Company, nor any arrangement or understanding between any Company officer and another person pursuant to which the officer was elected. Officers of the Company hold office until the first meeting of the directors following the next annual meeting of the stockholders and until their respective successors are chosen and qualified.

Name, Age and Position	Business Experience During Past Five Years
Thomas J. May, 47 Chairman of the Board and Chief Executive Officer	Chairman of the Board and Chief Executive Officer (since 1994), formerly President and Chief Operating Officer (1993-1994), Executive Vice President (1990-1993) and Senior Vice President (1987-1990). Director (since 1991). Chairman of the Board and Chief Executive Officer and Director, Harbor Electric Energy Company and Boston Energy Technology Group; Chairman of the Board and Chief Executive Officer, TravElectric Services Corp. and Ener-G-Vision, Inc.; Chairman of the Board, REZ-TEK International Corp. and Coneco Corp.
George W. Davis, 61 President and Chief Operating Officer	President and Chief Operating Officer (since 1994), formerly Executive Vice President (1992-1994), responsible for all power supply and delivery operations, Senior Vice President - Nuclear (1990-1992) and Vice President - Nuclear Administration (1989-1990). Director (since 1991). President and Director, Harbor Electric Energy Company and Boston Energy Technology Group; Director, TravElectric Services Corp. and Ener-G-Vision, Inc.

Name, Age and Position	Business Experience During Past Five Years
E. Thomas Boulette, 52 Senior Vice President - Nuclear	Senior Vice President - Nuclear (since 1993), Vice President - Nuclear Operations and Station Director (1992-1993) and Vice President - Operations (1989-1992) of Maine Yankee Atomic Power Company.
Cameron H. Daley, 49 Senior Vice President - Power Supply	Senior Vice President - Power Supply (since 1989).
L. Carl Gustin, 51 Senior Vice President - Marketing & Corporate Relations	Senior Vice President - Marketing & Corporate Relations (since 1989).
John J. Higgins, Jr., 62 Senior Vice President - Human Resources	Senior Vice President - Human Resources (since 1990) and Vice President - Human Resources (1988-1990).
Ronald A. Ledgett, 56 Senior Vice President - Power Delivery	Senior Vice President - Power Delivery (since 1991) and Director, Special Projects (1989-1991).
Charles E. Peters, Jr., 43 Senior Vice President - Finance	Senior Vice President - Finance (since 1991), formerly Chief Financial Officer and Senior Vice President of Genrad, Inc. (1985-1991). Senior Vice President, Treasurer and Director, Harbor Electric Energy Company and Boston Energy Technology Group; Director, TravElectric Services Corp., Ener-G-Vision, Inc., REZ-TEK International Corp. and Coneco Corp.
Marc S. Alpert, 50 Vice President and Treasurer	Vice President and Treasurer (since 1988). Assistant Treasurer, Harbor Electric Energy Company and Boston Energy Technology Group.

Name, Age and Position	Business Experience During Past Five Years
Robert J. Weafer, Jr., 48 Vice President, Controller and Chief Accounting Officer	Vice President, Controller and Chief Accounting Officer (since 1991). Controller (1988-1991) and Chief Accounting Officer (1983-1991).
Theodora S. Convisser, 47 Clerk of the Corporation	Clerk of the Corporation (since 1986). Clerk of Harbor Electric Energy Company, Boston Energy Technology Group, TravElectric Services Corp., Ener-G-Vision, Inc., REZ-TEK International Corp. and Coneco Corp.
Douglas S. Horan, 45 Vice President and General Counsel	Vice President and General Counsel (since 1994), formerly Deputy General Counsel (1991-1994) and Associate General Counsel (1986-1991). General Counsel of Harbor Electric Energy Company.

Part II

Item 5. Market for the Registrant's Common Stock and Related Stockholder Matters

(a) Market Information

The Company's common stock is listed on the New York and Boston Stock Exchanges.

Following are the reported high and low sales prices of the Company's common stock on the New York Stock Exchange as reported daily in the *Wall Street Journal* for each of the quarters in 1994 and 1993:

	1994		1993	
	High	Low	High	Low
First quarter	$29 7/8	$26	$30 1/2	$26 3/8
Second quarter	29 1/8	25 1/4	30 7/8	27 7/8
Third quarter	27 5/8	22 3/4	32 5/8	29 3/4
Fourth quarter	24 1/4	21 1/2	32 1/4	27 7/8

(b) Holders

As of December 31, 1994, the Company had 39,904 holders of record of its common stock (actual count of record holders).

(c) Dividends

Following are the dividends declared per share of common stock for each of the quarters in 1994 and 1993:

	1994	1993
First quarter	$0.440	$0.425
Second quarter	0.440	0.425
Third quarter	0.440	0.425
Fourth quarter	0.455	0.440

(d) Other Information

Ratio of earnings to fixed charges and ratio of earnings to fixed charges and preferred stock dividend requirements for the year ended December 31, 1994:

Ratio of earnings to fixed charges	2.45
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.07

Item 6. Selected Financial Data

The following table summarizes five years of selected consolidated financial data of the Company (in thousands, except per share data).

	1994	1993	1992	1991	1990
Operating revenues	$1,548,554	$1,482,253	$1,411,753	$1,354,501	$1,314,440
Net income	125,022	118,218	107,298	94,670	79,616(a)
Earnings per common share	2.41	2.28	2.10	1.96	1.60(a)
Total assets	3,616,610	3,477,288	3,294,234	3,119,285	3,012,589
Long-term debt	1,136,617	1,272,497	1,091,073	1,136,765	1,074,025
Redeemable preferred/ preference stock	219,000	221,000	221,000	221,333	221,333
Cash dividends declared per common share	1.775	1.715	1.655	1.595	1.535

(a) Before cumulative effect of change in accounting principle ($15,824 or $0.41 per common share).

Item 7. Management's Discussion and Analysis

Regulatory Proceedings

Retail settlement agreements

In 1992 our state regulators, the Massachusetts Department of Public Utilities, approved a three-year settlement agreement effective November 1992. This agreement provided us with retail rate increases, allowed for the recovery of demand side management (DSM) conservation program costs, specified certain accounting adjustments and clarified the timing and recognition of certain expenses. The agreement also set a limit on our rate of return on common equity of 11.75% for 1993 through 1995, excluding any penalties or rewards from performance incentives.

The retail rate increases consisted of a new annual performance adjustment charge effective November 1992 and two annual base rate increases of $29 million effective November 1993 and November 1994. The performance adjustment charge varies annually based upon the performance of our Pilgrim Nuclear Power Station. This charge is further described in our discussion of financial condition.

In addition to the retail rate increases, our results of operations were affected by the recovery of DSM program costs, accounting adjustments and the timing and recognition of certain expenses as further described in the following Results of Operations section.

Our state regulators previously approved a three-year settlement agreement effective November 1989. That agreement also provided us with retail rate increases and specified certain accounting adjustments. The 1989 agreement primarily affected our results of operations through 1992.

We do not currently plan to make a base rate filing upon the expiration of the 1992 settlement agreement, therefore we anticipate that base rates will remain in effect at their current levels.

Results of Operations

1994 versus 1993

Earnings per common share were $2.41 in 1994 and $2.28 in 1993. The increase in earnings was primarily the result of the expiration of a long-term purchased power contract in October 1993, a retail base rate increase effective November 1993, a 2.0% increase in retail kWh sales and an award relating to an eminent domain case. These positive changes were partially offset by higher operations and maintenance, depreciation and amortization and income tax expenses.

Operating revenues

Operating revenues increased 4.5% over 1993 as follows:

(in thousands)	
Retail electric revenues	$62,945
Demand side management revenues	5,056
Wholesale and other revenues	(2,919)
Short-term sales revenues	1,219
Increase in operating revenues	$66,301

Retail electric revenues increased $63 million. The November 1993 and 1994 base rate increases resulted in $28.6 million of the increased revenues and approximately $6 million was due to the 2% increase in retail sales. Fuel and purchased power revenues increased $28.5 million primarily due to the recovery of certain new purchased power expenses. In accordance with the 1992 settlement agreement specific revenues related to the purchased power contract that expired in October 1993 were not affected.

The decrease in wholesale and other revenues is primarily due to an estimated provision for refunds to wholesale customers due to contract issues.

Operating expenses

Total fuel and purchased power expenses decreased $27 million. Fuel expense decreased partly due to lower fossil fuel prices and a 12% decrease in nuclear output. Purchased power expense reflects lower costs associated with the long-term contract that expired in October 1993, partially offset by the costs of new contracts. The timing effect of fuel and purchased power cost collection also contributed to the decrease in fuel and purchased power expenses. Fuel and purchased power expenses are substantially all recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 8.7% primarily due to higher employee benefit expenses. Pension expense increased $20 million due to a higher contribution made to the pension plan for the year. In accordance with the 1992 settlement agreement, we record pension expense in the amount of the contribution to the plan.

Depreciation and amortization expense increased primarily due to a higher depreciable plant balance. In 1994 we fully expensed the remaining deferred costs of the cancelled Pilgrim 2 nuclear unit. In accordance with the 1992 settlement agreement we did not expense any of these costs in 1993.

Amortization of deferred nuclear outage costs consists of amounts related to the 1993 and 1991 refueling outages at Pilgrim Station. In 1993 we deferred approximately $14 million of refueling outage costs. We began to amortize these costs in June 1993 over five years as approved in the 1992 settlement agreement.

The $2 million decrease in demand side management programs expense was due to the timing of recovery of program costs. DSM expense includes some program costs recovered over twelve months and other program costs recovered over six years. The 1994 expense consists of $22 million of costs primarily related to 1994 expenditures and $13 million of costs capitalized in 1992 through 1994.

Municipal property and other taxes increased primarily as a result of higher Boston property taxes due to a tax rate increase and capital additions.

Our effective annual income tax rate for 1994 was 31.4% vs. 23.4% for 1993. Both rates were reduced by adjustments to deferred income taxes of $10 million in 1994 and $20 million in 1993 made in accordance with the 1992 settlement agreement. No further deferred income tax adjustments may be made and we expect our effective tax rate to be close to the statutory rate in 1995.

Other income

In November 1994 a court ruling became effective providing us with an additional $5.7 million gain on a 1989 eminent domain taking of our property.

Interest charges

Interest charges in total did not change significantly. Interest charges on long-term debt decreased due to the first mortgage bond and debenture redemptions in 1994 and the significant first mortgage bond refinancing in 1993 at lower interest rates. This decrease was partially offset by higher amortization of redemption premiums. Other interest charges increased due to higher short-term interest rates partially offset by a lower average short-term debt level. Allowance for borrowed funds used during construction (AFUDC), which represents the financing costs of construction, increased as a result of a higher AFUDC rate related to higher short-term interest rates.

1993 versus 1992

Earnings per common share were $2.28 in 1993 and $2.10 in 1992. The increase in earnings was primarily the result of a retail rate increase effective November 1992, the expiration of a long-term purchased power contract in October 1993, no amortization of deferred cancelled nuclear unit costs and lower interest expense. These positive changes were partially offset by higher operations and maintenance, income tax and property tax expenses.

Operating revenues

Operating revenues increased 5.0% over 1992 as follows:

(in thousands)	
Retail electric revenues	$70,837
Demand side management revenues	33,601
Wholesale and other revenues	(2,794)
Short-term sales revenues	(31,144)
Increase in operating revenues	$70,500

Retail electric revenues increased $71 million. The November 1992 and 1993 rate increases resulted in $40.6 million of additional revenues in 1993. Fuel and purchased power revenues increased $29.5 million over 1992 primarily due to the timing effect of fuel and purchased power cost collection and lower revenues received from short-term power sales as discussed below.

We began recovery of certain demand side management program costs, lost base revenues and incentives in August 1992. Our 1993 revenues provided $45.9 million related to 1991, 1992 and 1993 DSM programs. Our 1992 revenues of $12.3 million related primarily to 1991 programs.

The decrease in wholesale and other revenues reflects an estimated provision for refunds to customers of $8.6 million in 1993 as a result of orders from our state regulators on our gene. 'ing unit performance program.

Lower short-term power sales revenues were a result of changes in our generation availability and the needs of short-term power purchasers. Revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and therefore have no effect on earnings.

Operating expenses

Total fuel and purchased power expenses decreased $12 million. Fuel expense decreased primarily due to a 21.5% decrease in fossil generation and an 8.5% decrease in nuclear generation, resulting from planned plant overhauls and a nuclear refueling outage. Purchased power expense reflects both higher interchange purchases, caused by the lower generation, and lower costs associated with the long-term contract that expired in October 1993. The decreases in expense were partially offset by the timing effect of fuel and purchased power cost collection.

Other operations and maintenance expense increased 7.1% primarily due to increases in employee benefits and nuclear production expenses. Postretirement benefits expense increased by $7 million primarily as a result of the adoption of a new accounting standard and pension expense increased by $5 million; both are provided for in our 1992 settlement agreement and further explained in Note E to the consolidated financial statements. A refueling outage at Pilgrim Station in 1993 resulted in higher nuclear production expenses.

Depreciation and amortization expense increased in 1993 primarily due to a higher annual decommissioning charge for Pilgrim Station effective November 1992 provided by the 1992 settlement agreement. The charge is based on a 1991 estimate of decommissioning costs as further discussed in Note D to the consolidated financial statements. In addition, the effect of lower depreciation rates implemented in accordance with the settlement agreement was offset by the effect of a higher depreciable plant balance.

In accordance with our 1992 settlement agreement we did not expense any of the $19 million of remaining deferred costs associated with the cancelled Pilgrim 2 nuclear unit in 1993.

Amortization of deferred nuclear outage costs consists of amounts related to the 1993 and 1991 refueling outages at Pilgrim Station as discussed in the results of operations for 1994 versus 1993.

The increase in demand side management programs expense is consistent with the increase in DSM revenues. DSM expense includes some costs recovered over twelve months and other costs recovered over six years. We began to recover previously deferred DSM expenses in August 1992. In 1993 we expensed and collected from customers approximately $30 million of deferred 1991, 1992 and 1993 program costs. Over six years we are expensing and collecting from our customers $11 million of costs capitalized in 1992 and $37 million of costs capitalized in 1993. The 1993 expense related to these capitalized costs was $7 million.

Municipal property and other taxes increased in 1993 due to the absence of tax abatements. In 1992 property taxes were reduced by $10.4 million of tax abatements in accordance with our 1989 settlement agreement.

Our effective annual income tax rate for 1993 was 23.4% vs. 8.7% for 1992. Both rates were significantly reduced by adjustments to deferred income taxes of $20 million in 1993 and $23 million in 1992 made in accordance with the 1992 and 1989 settlement agreements. The 1992 rate was also reduced due to tax benefits of approximately $7 million resulting from mandated payments made in accordance with the 1989 agreement. Our adoption of a new accounting standard for income taxes in 1993 did not significantly affect earnings.

Interest charges and preferred and preference dividends

Total interest charges decreased $4 million in 1993. Interest on long-term debt decreased primarily due to the refinancing of substantially all our first mortgage bonds in 1993 at lower interest rates, partially offset by higher amortization of redemption premiums. Other interest charges decreased due to a lower short-term debt level and lower short-term interest rates. AFUDC decreased as a result of a lower AFUDC rate related to lower short-term interest rates.

Preferred and preference dividends decreased 5.1% due to the replacement of a preferred and a preference stock issue with less costly issues of preferred stock.

Financial Condition

Our 1992 settlement agreement is providing us with increased revenues from retail customers over the three-year period ending October 1995. Additionally, a significant long-term purchased power contract expired in October 1993 with no change in related revenues. The settlement agreement also limits the annual rate of return on equity during the three-year period to 11.75%, excluding any penalties or rewards from performance incentives.

Our ability to achieve or exceed the 11.75% rate of return on equity is primarily dependent upon our ability to control costs and to earn performance incentives from generation performance mechanisms. The most significant impact that incentives can have on our financial results is based on Pilgrim Station's annual capacity factor. An annual capacity factor between 60% and 68% would provide us with approximately $47 million of revenues in the performance year ended October 1995. For each percentage point increase in capacity factor above 68%, annual revenues will increase by approximately $690,000. For each percentage point decrease in capacity factor below 60% (to a minimum of 35%), annual revenues will decrease by approximately $790,000. Pilgrim's capacity factor for the performance year ending October 1995 is currently expected to be approximately 69%, a decrease from the 72% capacity factor achieved in the performance year ended October 1994, primarily due to the refueling outage scheduled for 1995. We earned approximately $47 million in revenues related to Pilgrim's capacity factor in the performance year ended October 31, 1994.

Pilgrim Station automatically shut down in August 1994 as a result of a non-nuclear problem with its electrical generator. The plant returned to service three months later following the completion of necessary repairs as well as maintenance work originally scheduled for an October 1994 mid-cycle outage. The power needs usually met by the station were met by our other generating plants or purchased from other suppliers as necessary. We do not believe that the generator damage resulted from actions within our control, however, our recovery of the incremental purchased power costs during the outage through fuel and purchased power revenues is subject to review by our state regulators under our generating unit performance program.

As discussed in Regulatory Proceedings, we do not plan to make a base rate filing with our state regulators upon the expiration of the 1992 settlement agreement, therefore we anticipate that our base rates will remain in effect at their current levels.

Liquidity

We meet our capital expenditure cash requirements primarily with internally generated funds. These funds provided for 98%, 76% and 88% of our plant and nuclear fuel expenditures in 1994, 1993 and 1992, respectively. Our current estimate of plant expenditures for 1995 is $200 million. These expenditures will be used primarily to maintain and improve existing transmission, distribution and generation facilities. We do not expect plant expenditures to vary significantly from the 1995 amount in the four years thereafter. We have long-term debt and preferred stock payment requirements of $102.6 million in 1995, $103.6 million per year in 1996 through 1998 and $3.6 million in 1999.

External financings continue to be necessary to supplement our internally generated funds, primarily through the issuance of short-term commercial paper and bank borrowings. We currently have authority from our federal regulators to issue up to $350 million of short-term debt. We have a $200 million revolving credit agreement and arrangements with several banks to provide additional short-term credit on a committed as well as on an uncommitted and as available basis. At December 31, 1994 we had $215 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. In 1994 our state regulators approved our financing plan to issue up to $500 million of securities through 1996. The proceeds will be used to refinance short and long-term securities and for capital expenditures. Refer to Note H to the consolidated financial statements for specific information relating to our recent financing activities.

Outlook for the Future

Electricity sales

A significant portion of our electricity sales are made to commercial customers rather than industrial customers. As a result our sales have been only moderately impacted by the unfavorable economic factors affecting the manufacturing industry in Massachusetts, including defense cutbacks and continued downsizing in the computer industry. Increased sales to commercial customers more than offset the decrease in sales to industrial customers as economic factors provided growth in the commercial sector in 1994. Total retail sales increased 2% in 1994.

Implementation of DSM programs, which are designed to assist customers in reducing electricity use, will result in lower growth in electricity sales. We receive approval from our state regulators for annual DSM spending levels and recovery amounts. Through 1994 we collected from customers certain DSM program costs primarily in the year incurred and other DSM program costs over a six-year period. We are also provided with incentives and recovery of lost revenues based on the actual reduction in customer electricity usage from these programs and a return on the costs that we recover over six years. Beginning in 1995 all costs are expected to be collected primarily in the year incurred. We will continue to recover the DSM costs capitalized during 1992 through 1994 along with a return on investment on the unrecovered balance.

Competition

The electric utility business is in a period of transition from a traditional rate-regulated environment based on cost recovery to an environment with both competition and modified regulation. The effects of competition to date have been most evident in the wholesale electric market. In response to increased competition from other electric utilities and non-utility generators to sell electricity for resale, we have secured long-term power supply agreements with our five wholesale customers. These agreements set our rates through the year 2002 and beyond.

We are also beginning to face some forms of competition in the retail electric market. This is happening as industrial and large commercial customers pursue their options to generate their own electric power, as customers look to obtain lower electricity prices and to substitute natural gas or oil for electricity for heating or cooling purposes and as large facilities factor the cost of electricity into their decisions to relocate into or out of a given service territory. In the future, the potential exists for electric utilities and other energy suppliers to sell electricity to retail customers of other electric utilities without regard for existing service territories. In addition, our state regulators are currently investigating two issues related to the onset of competition, incentive regulation and industry restructuring.

We are responding to the current and anticipated retail competitive challenges in several ways. We do not plan on seeking any additional base rate increases until at least the year 2000 and are working to accomplish this by controlling costs and increasing operating efficiencies without sacrificing quality of service or profitability. During 1994 we reduced our workforce by 8.4%, we negotiated six-year contracts with our two union locals which resulted in cost-saving changes and limits wage growth and we implemented various other cost control strategies. We also developed customer alliances and provided economic development rates to some customers. In addition, we filed with our state regulators for approval of lower rates for a small number of large manufacturing customers on a limited basis. These actions all signify our commitment to be a competitively priced, reliable provider of energy. We are also actively participating in regulatory and legislative discussions and proceedings concerning the future structure of the electric utility industry. We do not expect the economic development rates or the proposed lower manufacturing customer rates to have a significant impact on our financial condition or results of operations.

As a regulated company, we are subject to certain accounting rules that are not applicable to other businesses and industries. These accounting rules allow regulated companies, as appropriate, to record certain costs as regulatory assets instead of expenses when they are incurred. These regulatory assets are expected to be recovered from customers through future rates. The effects of competition or changes in regulation could ultimately cause us to no longer be able to follow these accounting rules, in which case our regulatory assets would have to be fully expensed at that time.

Resource regulation

Our state regulators require utilities to purchase power from qualifying non-utility generators at prices set through a bidding process. In 1993 our state regulators ordered us to purchase 132 megawatts of power from an independent power producer, Altresco Lynn, LP, starting as early as 1995. We oppose this order since we do not believe we need any new power for several years. We asked the Massachusetts Supreme Judicial Court (SJC) to reverse the order and in 1994 the SJC remanded the case to our state regulators for further consideration. Our regulators then issued an order requiring us to negotiate a contract with Altresco Lynn. We filed an appeal of this order with the SJC in October 1994 and are currently awaiting a decision. In addition, we supported an appeal filed by other parties of a state regulatory body's conditional approval of construction of Altresco Lynn's generating station project. In January 1995 the SJC reversed the regulator's approval on the basis that there was no showing of need for the project in Massachusetts prior to 2000.

We are also subject to our state regulators' integrated resource management (IRM) process in which electric utilities forecast their future energy needs and propose how they will meet those needs by balancing conservation programs with all other supplies of energy. We submitted an IRM filing in 1994 and received a favorable ruling in January 1995. Our regulators found that we do not have a need for additional resources through 2001 and we are not required to issue a competitive request for proposal for new generating capacity at this time. We are required to update our IRM filing in January 1996.

Non-utility business

In 1993 we created an unregulated subsidiary, Boston Energy Technology Group (BETG), following approval from our state regulators. We have authority to invest up to $45 million in this wholly-owned subsidiary. BETG engages in demand side management activities and businesses involving electric transportation and the related infrastructure through two wholly-owned subsidiaries. In 1994 BETG acquired a substantial majority interest in two additional businesses. REZ-TEK International Corp. produces systems that treat cooling water used in commercial and industrial air conditioning systems in an energy efficient and environmentally sound manner, and Coneco Corporation provides engineering and project management services to energy and water conservation project developers and contractors. These acquisitions were not material.

We do not currently have a substantial investment in BETG and do not anticipate it significantly impacting our results of operations in the next several years.

Other Matters

Environmental

We are subject to numerous federal, state and local standards with respect to waste disposal, air and water quality and other environmental considerations. These standards can require that we modify our existing facilities or incur increased operating costs.

We own or operate 48 properties where hazardous materials were released in the past. We are required to clean up these properties in accordance with a timetable developed by the Massachusetts Department of Environmental Protection (DEP) and are continuing to evaluate the costs associated with their cleanup. There are uncertainties associated with these costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of ten multi-party hazardous waste sites in Massachusetts and other states where we are alleged to have generated, transported or disposed of hazardous waste at the sites. At the majority of these sites we are one of many potentially responsible parties and we currently expect to have only a small percentage of the potential liability. Through December 31, 1994, we have accrued approximately $7 million related to our cleanup liabilities. We are unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount, although based on our assessments of the specific site circumstances, we do not expect any such additional costs to have a material impact on our financial condition. However, additional provisions for cleanup costs could have a material impact on our results of a reporting period.

Uncertainties continue to exist with respect to the disposal of both low-level radioactive waste (LLW) and spent nuclear fuel resulting from the operation of Pilgrim Station. In July 1994 our access to off-site LLW disposal facilities ended. Until access is attained to other disposal facilities we are managing LLW through on-site storage. The United States Department of Energy (DOE) is responsible for the ultimate disposal of spent nuclear fuel, however there are uncertainties regarding the DOE's schedule of acceptance of spent fuel for disposal. Refer to Note D to the consolidated financial statements for further discussion regarding LLW and spent nuclear fuel disposal.

Under a 1991 consent order with the DEP and other interested parties we made certain improvements in the emission control systems at New Boston Station. These improvements included the replacement of four existing chimney stacks with two taller stacks in order to improve the air quality in the vicinity of the station, and the installation of low nitrogen oxides burners. The capital costs of these modifications along with other associated improvements, which were substantially completed in 1994, were approximately $80 million.

New Boston Station has the ability to burn natural gas, oil or both. Beginning in April 1995, as part of the DEP consent order, we will be required to operate the station fueled exclusively by natural gas, except in certain emergency circumstances. We have made arrangements for a firm supply of natural gas to run the station at a minimum level. We are developing a least-cost plan for operation beyond this minimum level involving principally the utilization of interruptible gas supplies or short-term capacity purchases.

The 1990 Clean Air Act Amendments will require a significant reduction in nationwide emissions of sulfur dioxide from fossil fuel-fired generating units. The reduction will be accomplished by restricting sulfur dioxide emissions through a market-based system of allowances. We currently have allowances that are in excess of our needs and which may be marketable. Any gain from the sale of these may be subject to future regulatory treatment. Other provisions of the 1990 Clean Air Act Amendments involve limitations on emissions of nitrogen oxides from existing generating units. Combustion system modifications made to New Boston and Mystic Stations, including the installation of the low nitrogen oxides burners at New Boston, will allow the units to meet the provisions of the 1995 standards. Depending upon the outcome of certain DEP air quality modeling studies currently in progress, additional emission reductions may also be required by 1999. The extent of any additional reductions and the cost of any further modifications is uncertain at this time.

In recent years there have been increasing public concerns regarding electromagnetic fields (EMF) associated with electric transmission and distribution facilities and appliances and wiring in buildings and homes. Such concerns have included the possibility of adverse health effects caused by EMF as well as perceived effects on property values. Some scientific reviews conducted to date have suggested associations between EMF and potential health effects, while other studies have not substantiated such associations. We support further research into the subject and are participating in the funding of industry-sponsored studies. We are aware that public concern regarding EMF in some cases has resulted in litigation, in opposition to existing or proposed facilities in proceedings before regulators or in requests for legislation or regulatory standards concerning EMF levels. We have addressed issues relative to EMF in various legal and regulatory proceedings and in discussions with customers and other concerned persons; however, to date we have not been significantly affected by these developments. We continue to closely monitor all aspects of the EMF issue.

Litigation

In 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel continues to vigorously defend this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on our results of a reporting period.

Executive Office Changes

In July 1994 our former President, Thomas May, became Chairman and Chief Executive Officer, former Executive Vice President George Davis became President and Chief Operating Officer and former Chairman and Chief Executive Officer Bernard Reznicek retired. In January 1995 George Davis announced his anticipated retirement effective September 1995.

Item 8. Financial Statements and Supplementary Financial Information

Consolidated Statements of Income

(in thousands, except earnings per share)	years ended December 31, 1994	1993	1992
Operating revenues	$1,548,554	$1,482,253	$1,411,753
Operating expenses:			
Fuel	156,951	170,799	200,774
Purchased power	356,874	370,049	352,030
Other operations and maintenance	441,423	406,271	379,350
Depreciation and amortization	149,122	137,722	129,045
Amortization of deferred cost of cancelled nuclear unit	19,791	0	24,381
Amortization of deferred nuclear outage costs	7,721	6,546	4,901
Demand side management programs	35,438	37,504	8,221
Taxes - property and other	100,132	93,102	80,426
Income taxes	54,279	34,941	11,725
Total operating expenses	1,321,731	1,256,934	1,190,853
Operating income	226,823	225,319	220,900
Other income (expense), net	5,658	589	(2,074)
Operating and other income	232,481	225,908	218,826
Interest charges:			
Long-term debt	102,570	104,375	106,850
Other	12,367	9,778	12,525
Allowance for borrowed funds used during construction	(7,478)	(6,463)	(7,847)
Total interest charges	107,459	107,690	111,528
Net income	125,022	118,218	107,298
Preferred and preference dividends provided	15,765	15,705	16,550
Balance available for common stock	$ 109,257	$ 102,513	$ 90,748
Common shares outstanding (weighted average)	45,338	44,959	43,144
Earnings per share of common stock	$ 2.41	$ 2.28	$ 2.10

Consolidated Statements of Retained Earnings

(in thousands)	years ended December 31, 1994	1993	1992
Balance at beginning of year	$ 218,292	$ 192,948	$ 174,477
Net income	125,022	118,218	107,298
Subtotal	343,314	311,166	281,775
Cash dividends declared:			
Preferred stock	15,765	15,705	14,923
Preference stock	0	0	1,953
Common stock	80,545	77,169	71,951
Subtotal	96,310	92,874	88,827
Balance at end of year	$ 247,004	$ 218,292	$ 192,948

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Balance Sheets

(in thousands)		1994		December 31, 1993
Assets				
Utility plant, at original cost:				
In service	$4,074,810		$3,904,776	
Less: accumulated depreciation	1,344,452	$2,730,358	1,258,359	$2,646,417
Nuclear fuel	291,836		273,867	
Less: accumulated amortization	236,239	55,597	220,477	53,390
Construction work in progress		144,048		144,835
		2,930,003		2,844,642
Investments in electric companies, at equity		24,678		24,292
Nuclear decommissioning trust		82,831		66,060
Current assets:				
Cash and cash equivalents	6,822		8,768	
Accounts receivable	189,382		171,098	
Accrued unbilled revenues	32,240		29,823	
Fuel, materials and supplies, at average cost	71,560		79,381	
Prepaid expenses and other	26,705	326,709	9,738	298,808
Deferred debits:				
Regulatory assets	197,455		210,144	
Intangible asset-pension	22,849		0	
Other	32,085	252,389	33,342	243,486
Total assets		$3,616,610		$3,477,288
Capitalization and Liabilities				
Common stock equity		$ 915,747		$ 876,479
Cumulative preferred stock:				
Non-mandatory redeemable series		123,000		123,000
Mandatory redeemable series		94,000		96,000
Long-term debt		1,136,617		1,272,497
Current liabilities:				
Long-term debt/preferred stock due within one year	$102,250		$ 2,000	
Notes payable	214,786		204,151	
Accounts payable	139,119		117,614	
Interest accrued	24,464		25,467	
Dividends payable	23,533		22,696	
Pension benefits	31,908		22,005	
Other	76,615	612,675	32,477	426,410
Deferred credits:				
Power contracts	40,277		36,275	
Accumulated deferred income taxes	515,454		484,785	
Accumulated deferred investment tax credits	67,048		71,140	
Nuclear decommissioning reserve	92,404		73,744	
Other	19,388	734,571	16,958	682,902
Commitments and contingencies		-		-
Total capitalization and liabilities		$3,616,610		$3,477,288

The accompanying notes are an integral part of the consolidated financial statements.

Consolidated Statements of Cash Flows

(in thousands)	years ended December 31, 1994	1993	1992
Cash flows from operating activities:			
Net income	$125,022	$118,218	$107,298
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	142,932	130,074	123,243
Amortization of nuclear fuel	18,810	21,816	25,473
Amortization of deferred cost of cancelled nuclear unit, net	19,067	0	22,340
Amortization of deferred nuclear outage costs	7,721	6,546	4,901
Other amortization	13,967	9,433	2,132
Deferred income taxes	(4,184)	10,303	17,165
Investment tax credits	(4,092)	(4,073)	(4,273)
Allowance for borrowed funds used during construction	(7,478)	(6,463)	(7,847)
Net changes in:			
Accounts receivable and accrued unbilled revenues	(20,701)	13,206	(18,188)
Fuel, materials and supplies	3,093	9,722	(2,330)
Accounts payable	21,505	(18,465)	35,759
Rate and contract settlements	0	(175)	(31,363)
Other current assets and liabilities	36,908	25,209	3,575
Other, net	15,561	(19,548)	(15,844)
Net cash provided by operating activities	368,131	295,803	262,041
Investing activities:			
Plant expenditures (excluding AFUDC)	(198,760)	(246,763)	(213,827)
Nuclear fuel expenditures	(21,934)	(6,491)	(17,198)
Capitalized demand side management expenditures	(37,007)	(37,156)	(11,469)
Sale of plant assets, net	15,972	0	0
Nuclear decommissioning trust investments	(16,771)	(15,189)	(7,210)
Electric company investments	(386)	1,106	1,836
Net cash used by investing activities	(258,886)	(304,493)	(247,868)
Financing activities:			
Issuances:			
Common stock	10,634	10,855	70,412
Preferred stock	0	40,000	40,000
Long-term debt	15,000	815,000	60,000
Redemptions:			
Preferred and preference stock	(2,000)	(40,000)	(40,333)
Long-term debt retirements	(50,000)	(648,625)	(123,600)
Net change in short-term debt	10,635	(71,349)	65,200
Dividends paid	(95,460)	(92,370)	(86,184)
Net cash provided (used) by financing activities	(111,191)	13,511	(14,505)
Net increase (decrease) in cash and cash equivalents	(1,946)	4,821	(332)
Cash and cash equivalents at the beginning of the year	8,768	3,947	4,279
Cash and cash equivalents at the end of the year	$ 6,822	$ 8,768	$ 3,947
Cash paid during the year for:			
Interest, net of amounts capitalized	$108,462	$103,720	$113,076
Income taxes	$ 46,074	$ 30,305	$ 10,095

The accompanying notes are an integral part of the consolidated financial statements.

Notes to Consolidated Financial Statements

Note A. Significant Accounting Policies

1. *Basis of Consolidation and Accounting*

The consolidated financial statements include the activities of our wholly-owned subsidiaries, Harbor Electric Energy Company and Boston Energy Technology Group. All significant intercompany transactions have been eliminated.

We follow accounting policies prescribed by our federal and state regulators. We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The financial statements comply with generally accepted accounting principles. Certain prior period amounts on the financial statements were reclassified to conform with current presentation.

2. *Revenues*

We record revenues for electricity used by our customers but not yet billed at the end of each accounting period.

3. *Forecasted Fuel and Purchased Power Rates*

The rate charged to retail customers for fuel and purchased power allows for fuel and some purchased power costs to be billed to customers using a forecasted rate. The difference between actual and estimated costs is recorded as an adjustment to fuel and purchased power expenses and is included in accounts receivable until subsequent rates are adjusted. State regulators have the right to reduce our subsequent fuel and purchased power rates if they find that we have been unreasonable or imprudent in the operation of our generating units or in purchasing fuel.

4. *Depreciation and Nuclear Fuel Amortization*

Our physical property was depreciated on a straight-line basis in 1994, 1993 and 1992 at composite rates of 3.11%, 3.09% and 3.36% per year, respectively, based on estimated useful lives of the various classes of property. The cost of decommissioning Pilgrim Station, our nuclear unit, is excluded from the depreciation rates. When property units are retired, their cost, net of salvage value, is charged to accumulated depreciation.

The cost of nuclear fuel is amortized based on the amount of energy Pilgrim Station produces. Nuclear fuel expense also includes an amount for the estimated costs of ultimately disposing of the spent nuclear fuel and for assessments for the decontamination and decommissioning of United States Department of Energy nuclear enrichment facilities. These costs are recovered from our customers through fuel rates.

5. *Amortization of Deferred Nuclear Outage Costs*

We expense deferred nuclear outage costs over five years as approved in the 1992 settlement agreement. The deferred cost balances in 1994 and 1993 consist of amounts related to the 1993 and 1991 refueling outages at Pilgrim Station.

6. Amortization of Discounts, Premiums and Redemption Premiums on Debt

We expense discounts, premiums, redemption premiums and related costs associated with issuances or redemptions of long-term debt or the refinancing of existing debt over the life of the debt or the replacement debt subject to regulatory approval.

7. Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated costs to finance plant expenditures. In accordance with regulatory accounting, AFUDC is included as a cost of utility plant and a reduction of interest charges. Although AFUDC is not a current source of cash income, the costs are recovered from customers over the service life of the related plant in the form of increased revenues collected as a result of higher depreciation expense. Our AFUDC rates in 1994, 1993 and 1992 were 4.45%, 3.62% and 4.48%, respectively, and represented only the cost of short-term debt.

8. Cash and Cash Equivalents

Cash and cash equivalents are comprised of highly liquid securities with maturities of three months or less. Outstanding checks are included in cash and accounts payable until they are presented for payment.

9. Allowance for Doubtful Accounts

Our accounts receivable are substantially all recoverable. This recovery occurs both from customer payments and from the portion of customer charges that provides for the recovery of bad debt expense. Accordingly, we do not maintain a significant allowance for doubtful accounts balance.

10. Regulatory Assets

Regulatory assets represent costs incurred which will be collected from customers through future charges in accordance with agreements with our state regulators. These costs are to be expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. A portion of these costs is currently being recovered from customers. No return on investment was earned on the regulatory assets.

Regulatory assets consisted of the following:

		December 31,
	1994	1993
Redemption premiums	$52,859	$59,116
Income taxes, net	44,745	26,916
Power contracts	40,277	36,275
Pension and postretirement costs	22,761	24,416
Nuclear outage costs	17,804	25,524
Cancelled nuclear unit	0	19,067
Other	19,009	18,830
	$197,455	$210,144

Note B. Retail Settlement Agreements

In 1992 and 1989 our state regulators, the Massachusetts Department of Public Utilities, approved three-year settlement agreements relating to our rate case proceedings. These agreements provided for retail rate increases, accounting adjustments and demand side management program expenditures; clarified the timing and recognition of certain expenses and set limits on our rate of return on common equity. Refer to Management's Discussion and Analysis for further information related to these settlement agreements.

The settlement agreements did not affect our contract or wholesale power rates charged to other utilities, which are regulated by our federal regulators, the Federal Energy Regulatory Commission.

Note C. Income Taxes

In 1993 we prospectively adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). This required us to change our methodology of accounting for income taxes from the deferred method to an asset and liability approach. The deferred method was based on the tax effects of timing differences between income for financial reporting purposes and taxable income. The asset and liability approach requires the recognition of deferred tax assets and liabilities for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. In accordance with SFAS 109 we recorded net regulatory assets of $44.7 million and $26.9 million and corresponding net increases in accumulated deferred income taxes as of December 31, 1994 and December 31, 1993, respectively. The regulatory assets represent the additional future revenues to be collected from customers for deferred income taxes.

Accumulated deferred income taxes consisted of the following:

		December 31,
(in thousands)	1994	1993
Deferred tax liabilities:		
Plant-related	$511,572	$496,731
Other	105,786	95,161
	617,358	591,892
Deferred tax assets:		
Plant-related	13,216	9,999
Investment tax credits	43,273	45,914
Alternative minimum tax	1,332	18,672
Other	44,083	32,522
	101,904	107,107
Net accumulated deferred income taxes	$515,454	$484,785

No valuation allowances for deferred tax assets are deemed necessary.

Components of income tax expense were as follows:

	years ended December 31,		
(in thousands)	1994	1993	1992
Current income tax expense	$62,839	$28,711	$ (385)
Deferred tax expense	(4,468)	10,303	16,383
Investment tax credits	(4,092)	(4,073)	(4,273)
Income taxes charged to operations	54,279	34,941	11,725
Taxes on other income:			
Current	2,550	1,205	(2,348)
Deferred	284	0	782
	2,834	1,205	(1,566)
Total income tax expense	$57,113	$36,146	$10,159

The effective income tax rates reflected in the consolidated financial statements and the reasons for their differences from the statutory federal income tax rate were as follows:

	1994	1993	1992
Statutory tax rate	35.0%	35.0%	34.0%
State income tax, net of federal income tax benefit	4.3	4.2	3.9
Investment tax credits	(2.3)	(2.6)	(3.6)
Municipal property tax adjustment	-	(0.6)	(1.6)
Adjustment of deferred taxes on cancelled nuclear unit	-	-	2.7
Reversal of deferred taxes-settlement agreement	(5.5)	(13.0)	(19.6)
Federal tax benefit of mandated payments from settlement agreements	-	-	(6.2)
Other	(0.1)	0.4	(0.9)
Effective tax rate	31.4%	23.4%	8.7%

Note D. Nuclear Decommissioning and Nuclear Waste Disposal

1. Nuclear Decommissioning

When Pilgrim Station's operating license expires in 2012 we will be required to decommission the plant. We are expensing an estimate of the decommissioning costs over Pilgrim's expected service life. The 1994 expense of approximately $15 million is included in depreciation expense on the consolidated income statement. The estimate used to determine our annual expense is based on a 1991 study which documents a cost of approximately $328 million to decommission the plant using the "green field" method, which provides for the plant site to be completely restored to its original state. The cost estimate, which involves many uncertainties, was incorporated in our 1992 retail settlement agreement. We receive recovery of the annual expense from charges to our retail customers and from other utility companies and municipalities who purchase a contracted amount of Pilgrim's electric generation. The funds we collect from decommissioning charges are deposited in an external trust and are restricted so that they may only be used for decommissioning and related expenses. The net earnings on the trust funds, which are also restricted, increase the nuclear decommissioning fund balance and nuclear decommissioning reserve, thus reducing the amount to be collected from customers.

The 1991 decommissioning study was partially updated for internal planning purposes to evaluate the potential impact of long-term spent fuel storage options resulting from delays in United States Department of Energy (DOE) spent fuel removal on the estimated decommissioning cost. (See part 2 below for a discussion of spent fuel removal). The partial update indicates an estimated decommissioning cost of approximately $400 million in 1991 dollars based upon a revised spent fuel removal schedule and utilization of dry spent fuel storage technology. No further update is currently available, however we will continue to monitor DOE spent fuel removal schedules and developments in spent fuel storage technology along with their impact on the decommissioning estimate.

In 1994 the Financial Accounting Standards Board began to review the accounting for decommissioning. If current industry accounting practices are changed our annual decommissioning expense could increase and trust fund earnings could be reported as investment income. In addition, the total estimated liability for decommissioning costs may be recorded on the balance sheet, most likely fully offset by an addition to utility plant costs. We do not expect that these potential changes would have a material effect on our results of operations.

2. *Spent Nuclear Fuel*

In 1994 we received a license amendment from the Nuclear Regulatory Commission to modify our fuel storage facility at Pilgrim Station to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012. We have modified the facility to provide spent fuel storage capacity through approximately 2003, however any further modifications are subject to review by our state regulators. In addition we are actively exploring the feasibility of other spent fuel storage facilities and technologies.

It is the ultimate responsibility of the DOE to permanently dispose of spent nuclear fuel as required by the Nuclear Waste Policy Act of 1982. We currently pay a fee of $1.00 per net megawatthour sold from Pilgrim Station generation under a nuclear fuel disposal contract with the DOE. The fee is collected from customers through fuel charges. The DOE is currently conducting scientific studies evaluating a potential spent nuclear fuel repository site at Yucca Mountain, Nevada. The potential site, however, has encountered substantial public and political opposition and the DOE has publicly stated that it may be unable to construct such a repository in a timely manner. In June 1994 we and other interested parties filed petitions in the U.S. Court of Appeals for the D.C. Circuit seeking declaratory rulings that the DOE is obligated to begin taking spent nuclear fuel for disposal in 1998. The DOE has sought to dismiss those petitions and a court ruling is awaited. It is unknown at this time whether and on what schedule the DOE will eventually construct a spent fuel repository and what the effect on us will be of any delays in such construction.

3. *Low-Level Radioactive Waste*

Our access to low-level radioactive waste (LLW) disposal facilities located in Barnwell, South Carolina ended in July 1994. Until access is attained to other disposal facilities we are managing LLW generated at Pilgrim Station through on-site storage. Legislation has been enacted in Massachusetts establishing a regulatory process for managing the state's LLW including the possible siting, licensing and construction of a disposal facility within the state, or, alternatively, an agreement with one or more other states. However, it appears unlikely that either option will be available in the near future. Pending the construction of a disposal facility within the state or the adoption by the state of some other LLW management procedure, we will continue to monitor the situation and investigate other available options.

4. *Other Nuclear Units*

We are an investor in and customer of two other domestic nuclear units. Both of these units receive, through the rates charged to their customers, an amount to cover the estimated costs to dispose of their spent nuclear fuel and to decommission the units at the end of their useful lives.

Note E. Pensions, Other Postretirement and Postemployment Benefits

1. Pensions

We have a defined benefit funded retirement plan with certain contributory features that covers substantially all employees. Benefits are based upon an employee's years of service and compensation during the last years of employment. Our funding policy is to contribute an amount each year that is not less than the minimum required contribution under federal law or greater than the maximum tax deductible amount. Plan assets are primarily equities, bonds, insurance contracts and real estate funds.

Net pension cost consisted of the following components:

(in thousands)	years ended December 31, 1994	1993	1992
Current service cost - benefits earned	$15,057	$ 11,734	$ 10,683
Interest cost on projected benefit obligation	33,961	33,181	32,287
Actual net loss/(return) on plan assets	214	(44,470)	(23,281)
Net amortization and deferral	(32,169)	8,528	(13,549)
Net pension cost (a)	$17,063	$ 8,973	$ 6,140

(a) In accordance with an agreement with our state regulators we deferred the difference in net pension costs and the annual funding amounts. Net deferred costs amounted to $6 million and $14 million at December 31, 1994 and 1993, respectively. Net pension costs recorded as expense were $25 million in 1994, $5 million in 1993 and $0 in 1992.

We used the following assumptions for calculating pension cost:

	1994	1993	1992
Discount rate	7.00%	8.25%	8.25%
Expected long-term rate of return on assets	10.00%	10.00%	10.00%
Compensation increase rate	4.50%	4.50%	4.50%

The pension plan's funded status was as follows:

(in thousands)	December 31, 1994	1993
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $305,632 and $384,150	$321,072	$400,895
Plan assets at fair value	$289,164	$394,233
Projected obligation for service rendered to date	(387,910)	(509,661)
Projected benefit obligation in excess of plan assets	(98,746)	(115,428)
Unrecognized prior service cost	13,328	8,139
Unrecognized net loss	67,361	75,352
Unrecognized net obligation	8,998	9,932
Minimum liability adjustment (b)	(22,849)	0
Net pension liability	$(31,908)	$(22,005)

(b) Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions (SFAS 87), requires the recognition of an additional minimum liability for the excess of accumulated benefits over the fair value of plan assets and accrued pension costs. In accordance with SFAS 87 we recorded an additional minimum liability and corresponding intangible asset of $23 million on our consolidated balance sheet at December 31, 1994.

We used the following assumptions for calculating the plan's year-end funded status:

	1994	1993
Discount rate	8.25%	7.00%
Compensation increase rate	3.90%	4.50%

We also provide defined contribution 401(k) plans for substantially all our employees. We match a percentage of employees' voluntary contributions to the plans, which amounted to $8 million in 1994, $7 million in 1993 and $5 million in 1992.

2. *Other Postretirement Benefits*

In addition to pension benefits, we also currently provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. In 1993 we adopted Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). This requires us to record a liability during the working years of employees for the expected costs of providing their postretirement benefits other than pensions (PBOPs). Prior to 1993 our policy was to record the cost of PBOPs when paid. Our transition obligation upon adopting this standard was approximately $183 million, which we elected to recognize over 20 years as permitted by SFAS 106.

Our 1992 settlement agreement provides us with a phase-in of a portion of the higher PBOP costs incurred under SFAS 106 and allows us to defer the additional costs in excess of the phase-in amounts to the extent that we fund an external trust. Our funding policy is to contribute 100% of postretirement benefit costs to external trusts. Accordingly, we recorded expenses of $17 million in 1994 and $15 million in 1993, reflecting the amount of current cost recovery from customers, and deferred the net costs in excess of amounts expensed for future recovery. Net deferred costs amounted to $16 million and $10 million at December 31, 1994 and 1993, respectively.

Net postretirement benefits cost consisted of the following components:

(in thousands)	years ended December 31, 1994	1993
Current service cost - benefits earned	$ 4,978	$ 4,351
Interest cost on accumulated benefit obligation	13,632	14,286
Actual return on plan assets	(187)	0
Amortization of transition obligation	9,151	9,151
Net amortization and deferral	(2,581)	0
Net postretirement benefits cost	$24,993	$27,788

We used the following assumptions for calculating postretirement benefits cost:

	1994	1993
Discount rate	7.0%	8.0%
Expected long-term rate of return on assets	9.0%	9.0%
Health care cost trend rate	9.0%	12.5%

The health care cost trend rate is assumed to decrease by one percent each year beginning in 1995 to 5% in 1998 and years thereafter. Changes in the health care cost trend rate will affect our cost and obligation amounts. A one percent increase in the assumed health care cost trend rate would increase the total service and interest cost components by 20% and would increase the accumulated benefit obligation at December 31, 1994 by 18%.

The postretirement benefits program's funded status was as follows:

(in thousands)		1994		December 31, 1993
Trust assets at fair value		$ 33,300		$ 18,016
Accumulated obligation for service rendered to date from:				
Retirees	$(93,960)		$(75,216)	
Active employees eligible to retire	(31,159)		(64,880)	
Active employees not eligible to retire	(51,545)	(176,664)	(73,285)	(213,381)
Accumulated benefit obligation in excess of trust assets		(143,364)		(195,365)
Unrecognized prior service cost		(19,502)		0
Unrecognized net (gain)/loss		(1,849)		21,497
Unrecognized transition obligation		164,715		173,868
Net postretirement benefits liability		$ 0		$ 0

The weighted average discount rates we used to measure the accumulated benefit obligation were 8.25% in 1994 and 7.0% in 1993. The trust assets consist of equities, bonds and money market funds.

3. Postemployment Benefits

In 1994 we adopted Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits (SFAS 112). This required us to record a liability for the estimated costs of providing postemployment benefits. Postemployment benefits provided to former or inactive employees, their beneficiaries and covered dependents consist primarily of disability-related benefits, including workers' compensation. We previously recognized the costs of these benefits primarily as claims were paid. The adoption of SFAS 112 did not have a material effect on our results of operations.

Note F. Eminent Domain Taking

In November 1994 a Norfolk Superior Court ruling against the Massachusetts Metropolitan District Commission (MDC) became effective, providing us with an additional $5.7 million gain on an eminent domain land taking case. We had filed suit against the MDC in 1992 related to the eminent domain taking of certain of our property in 1989.

Note G. Cancelled Nuclear Unit

In May 1982 we began to expense the cost of our cancelled Pilgrim 2 nuclear unit over approximately eleven and one-half years in accordance with an order received from state regulators. We did not expense any of these costs in 1993. The remaining balance of $19 million was fully expensed in 1994 as allowed by our state regulators in our 1992 settlement agreement.

Note H. Capital Stock and Indebtedness

Capital Stock

(dollars in thousands, except per share amounts)			1994	December 31, 1993	1992
Common stock equity:					
Common stock, par value $1 per share, 100,000,000 shares authorized; 45,535,477, 45,129,227 and 44,763,055 shares issued and outstanding:			$ 45,535	$ 45,129	$ 44,763
Premium on common stock			622,803	612,653	602,196
Retained earnings			247,004	218,292	192,948
Surplus invested in plant			405	405	405
Total common stock equity			$915,747	$876,479	$840,312
Cumulative preferred stock:					
Par value $100 per share, 2,890,000 shares authorized; issued and outstanding:					
Non-mandatory redeemable series:					
Series	Current Shares Outstanding	Redemption Price/Share			
4.25%	180,000	$103.625	$ 18,000	$ 18,000	$ 18,000
4.78%	250,000	$102.800	25,000	25,000	25,000
7.75%	400,000	-	40,000	40,000	0
8.25%	400,000	-	40,000	40,000	40,000
8.88%	0	-	0	0	40,000
Total non-mandatory redeemable series			$123,000	$123,000	$123,000
Mandatory redeemable series:					
Series	Current Shares Outstanding				
7.27%	460,000		$ 46,000	$ 48,000	$ 48,000
8.00%	500,000		50,000	50,000	50,000
Total mandatory redeemable series			96,000	98,000	98,000
Less: due within one year			2,000	2,000	0
Total mandatory redeemable series, net			$ 94,000	$ 96,000	$ 98,000

Dividends Declared per Share

	1994	1993	1992
Common stock	$ 1.775	$ 1.715	$ 1.655
Preferred stock:			
4.25% series	$ 4.250	$ 4.253	$ 4.250
4.78% series	4.780	4.785	4.780
7.27% series	7.270	7.270	7.270
7.75% series	7.750	5.707	0
8.00% series	8.000	8.000	8.000
8.25% series	8.250	8.250	5.278
8.88% series	0	2.220	8.880
Preference stock:			
$1.46 series	$ 0	$ 0	$ 0.365

Indebtedness

(dollars in thousands)	1994	December 31, 1993
Long-term debt:		
First mortgage bonds:		
Series S, variable rate, due 2002	$ 0	$ 25,000
Series U, 10.250%, due 2014	0	15,000
Total first mortgage bonds	0	40,000
Sewage facility revenue bonds	36,300	36,300
Less: due within one year	600	0
Less: funds held by trustee	4,083	3,803
Net long-term sewage facility revenue bonds	31,617	32,497
Debentures:		
8.875%, due 1995	100,000	100,000
5.125%, due 1996	100,000	100,000
5.700%, due 1997	100,000	100,000
5.950%, due 1998	100,000	100,000
6.800%, due 2000	65,000	65,000
6.050%, due 2000	100,000	100,000
6.800%, due 2003	150,000	150,000
9.875%, due 2020	100,000	100,000
9.375%, due 2021	115,000	125,000
8.250%, due 2022	60,000	60,000
7.800%, due 2023	200,000	200,000
Total debentures	1,190,000	1,200,000
Less: due within one year	100,000	0
Net long-term debentures	1,090,000	1,200,000
Massachusetts Industrial Finance Agency bonds:		
5.750%, due 2014	15,000	0
Total long-term debt	$1,136,617	$1,272,497
Short-term debt:		
Notes payable:		
Bank loans	$ 80,786	$ 106,501
Commercial paper	134,000	97,650
Total notes payable	$ 214,786	$ 204,151

1. Common Stock

Since December 31, 1991, we issued the following shares of common stock:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
Balance December 31, 1991	42,047	$42,047	$536,567
Dividend reinvestment plan	416	416	9,658
New issue (a)	2,300	2,300	55,971
Balance December 31, 1992	44,763	44,763	602,196
Dividend reinvestment plan	366	366	10,457
Balance December 31, 1993	45,129	45,129	612,653
Dividend reinvestment plan (b)	406	406	10,150
Balance December 31, 1994	45,535	$45,535	$622,803

(a) We used the net proceeds of the 1992 common stock issuance to reduce short-term debt.

(b) At December 31, 1994, the remaining authorized common shares reserved for future issuance under the Dividend Reinvestment and Common Stock Purchase Plan were 2,408,920 shares.

2. Cumulative Non-Mandatory Redeemable Preferred Stock

In May 1993 we issued 400,000 shares of 7.75% cumulative non-mandatory redeemable preferred stock at par. The stock is redeemable at $100 per share plus accrued dividends beginning in May 1998. These shares were sold in the form of 1.6 million depositary shares, each representing a one-fourth interest in a share of the preferred stock. We used the proceeds of this issue to fully retire the 8.88% series cumulative non-mandatory redeemable preferred stock.

3. Cumulative Mandatory Redeemable Preferred Stock

The 460,000 shares of our 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $103.88. The redemption price declines annually each May to par value in May 2002. The stock is subject to a mandatory sinking fund requirement of 20,000 shares each May at par plus accrued dividends. We also have the non-cumulative option each May to redeem additional shares, not to exceed 20,000, through the sinking fund at $100 per share plus accrued dividends.

We are not able to redeem any part of our 500,000 shares of 8% series cumulative preferred stock prior to December 2001. The entire series is subject to mandatory redemption in December 2001 at $100 per share, plus accrued dividends.

4. Long-Term Debt

The aggregate principal amounts of our debentures and sewage facility revenue bonds (including sinking fund requirements) due are $100.6 million in 1995, $101.6 million per year in 1996 through 1998 and $1.6 million in 1999.

In February 1993 we issued $65 million of 6.80% debentures due in 2000. We used the proceeds of this issue to reduce short-term debt. These debentures are not redeemable prior to maturity.

In March 1993 we issued $650 million of debentures and used the proceeds to retire ten series of first mortgage bonds and reduce short-term debt. The debentures were issued in five separate series with interest rates ranging from 5.125% to 7.8% and maturing between 1996 and 2023. The 5 1/8% debentures due 1996, 5.70% due 1997, 5.95% due 1998 and 6.80% due 2003 are not redeemable prior to maturity. The 7.80% debentures due 2023 are first redeemable in March 2003 at a redemption price of 103.73%. The redemption price decreases annually each March to par value in March 2013. There is no sinking fund requirement for any series of these debentures.

In August 1993 we issued $100 million of 6.05% debentures due in 2000. We used the proceeds from this sale to reduce short-term debt. These debentures are not redeemable prior to maturity and have no sinking fund requirements.

In March 1994 the Massachusetts Industrial Finance Agency, on our behalf, issued $15 million of 5.75% tax-exempt unsecured bonds due in 2014. The bonds are redeemable beginning in February 2004 at a redemption price of 102%. The redemption price decreases to 101% in February 2005 and to par in February 2006. The proceeds from this issuance together with sufficient other funds were used to fully redeem the Series U first mortgage bonds.

We redeemed at par the $25 million variable rate Series S first mortgage bonds in 1994. These bonds paid interest at 9.2% for the period January 15, 1993 through January 14, 1994. The rate was adjusted to 8.2% beginning January 15, 1994 based upon the ten-year constant maturity Treasury rate as published by the Federal Reserve Board.

As a result of the redemption of all outstanding first mortgage bonds, the Indenture of Trust and First Mortgage that had mortgaged substantially all our property since 1940 was terminated in November 1994.

Sewage facility revenue bonds were issued by Harbor Electric Energy Company (HEEC), a wholly-owned subsidiary. The bonds are tax-exempt, subject to annual mandatory sinking fund redemption requirements and mature in the years 1995-2015. The weighted average interest rate of the bonds is 7.3%. A portion of the proceeds from the bonds is in reserve with the trustee. If HEEC should have insufficient funds to pay certain costs on a timely basis or be unable to meet certain net worth requirements, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $7 million.

5. Short-Term Debt

We have arrangements with certain banks to provide short-term credit on both a committed and an uncommitted and as available basis. We currently have authority to issue up to $350 million of short-term debt.

We have a $200 million revolving credit agreement with a group of banks. This agreement is intended to provide a standby source of short-term borrowings. Under the terms of this agreement we are required to maintain a common equity ratio of not less than 30% at all times. Commitment fees must be paid on the unused portion of the total agreement amount.

Information regarding our short-term borrowings, comprised of bank loans and commercial paper is as follows:

(in thousands of dollars)	1994	1993	1992
Maximum short-term borrowings	$268,100	$320,000	$314,998
Weighted average amount outstanding	$214,640	$220,149	$233,286
Weighted average interest rates, excluding commitment fees	4.5%	3.4%	4.1%

Note I. Fair Value of Securities

The following methods and assumptions were used to estimate the fair value of each class of securities for which it is practicable to estimate the value:

Nuclear decommissioning trust
The cost of $82.8 million approximates fair value based on quoted market prices of securities held.

Cash and cash equivalents
The carrying amount of $6.8 million approximates fair value due to the short-term nature of these securities.

Mandatory redeemable cumulative preferred stock, sewage facility revenue bonds and unsecured debt
The fair values of these securities are based upon the quoted market prices of similar issues. Carrying amounts and fair values as of December 31, 1994 are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 96,000	$ 93,780
Sewage facility revenue bonds	36,300	37,037
Unsecured debt	1,205,000	1,111,317

Note J. New Accounting Pronouncement

Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities, became effective in 1994. This statement did not have a material effect on our consolidated financial statements.

Note K. Commitments and Contingencies

1. Capital Commitments

At December 31, 1994, we had estimated contractual obligations for plant and equipment of approximately $50 million.

2. Lease Commitments

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both noncancellable leases and transmission agreements for the years after 1994 are as follows:

(in thousands)	
1995	$ 26,540
1996	24,305
1997	21,396
1998	19,438
1999	17,794
Years thereafter	127,646
Total	$237,119

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. Our total expense for both lease rentals and transmission agreements was $27 million in 1994 and $30 million in 1993 and 1992, net of capitalized expenses of $4 million in 1994 and $5 million in 1993 and 1992.

3. Hydro-Quebec

We have an approximately 11% equity ownership interest in two companies which own and operate transmission facilities to import electricity from the Hydro-Quebec system in Canada, which is included in our consolidated financial statements. As an equity participant we are required to guarantee, in addition to our own share, the total obligations of those participants who do not meet certain credit criteria and are compensated accordingly. At December 31, 1994, our portion of these guarantees was approximately $21 million.

4. *Yankee Atomic Electric Company*

We have a 9.5% stock investment of approximately $2.5 million in Yankee Atomic Electric Company (Yankee Atomic). In 1992 the Board of Directors of Yankee Atomic decided to permanently discontinue power operation of the Yankee Atomic nuclear generating station and decommission the facility. We relied on Yankee Atomic for less than one percent of our system capacity under a long-term purchased power contract.

In 1993 Yankee Atomic received approval from federal regulators to continue to collect its investment and decommissioning costs through July 2000, the period of the plant's operating license. The estimate of our share of Yankee Atomic's investment and costs of decommissioning is approximately $39 million as of December 31, 1994. This estimate is recorded on our consolidated balance sheet as a power contract liability and an offsetting regulatory asset as we continue to collect these costs from our customers in accordance with our 1992 settlement agreement.

5. *Nuclear Insurance*

The federal Price-Anderson Act currently provides approximately $8.9 billion of financial protection for public liability claims and legal costs arising from a single nuclear-related accident. The first $200 million of nuclear liability is covered by commercial insurance. Additional nuclear liability insurance up to approximately $8.3 billion is provided by a retrospective assessment of up to $75.5 million per incident levied on each of the 110 units licensed to operate in the United States, with a maximum assessment of $10 million per reactor per accident in any year. The additional nuclear liability insurance amount may change as existing units give up their licenses. In addition to the nuclear liability retrospective assessments, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection, each licensee can be assessed an additional five percent of the maximum retrospective assessment.

We have purchased insurance from Nuclear Electric Insurance Limited (NEIL) to cover some of the costs to purchase replacement power during a prolonged accidental outage at Pilgrim Station and the cost of repair, replacement, decontamination or decommissioning of our utility property resulting from covered incidents at Pilgrim Station. Our maximum potential total assessment for losses which occur during current policy years is approximately $14.8 million under both the replacement power and excess property damage, decontamination and decommissioning policies. All companies insured with NEIL are subject to retroactive assessments if losses are in excess of the total funds available to NEIL. While assessments may also be made for losses in certain prior policy years, we are not aware of any losses in those years which we believe are likely to result in an assessment.

6. *Litigation*

In 1991 we were named in a lawsuit alleging discriminatory employment practices under the Age Discrimination in Employment Act of 1967 concerning 46 employees affected by our 1988 reduction in force. Legal counsel continues to vigorously defend this case. Based on the information presently available we do not expect that this litigation or certain other legal matters in which we are currently involved will have a material impact on our financial condition. However, an unfavorable decision ordered against us could have a material impact on our results of a reporting period.

7. ***Hazardous Waste***

We own or operate 48 properties where hazardous materials were released in the past. We are required to clean up these properties in accordance with a timetable developed by the Massachusetts Department of Environmental Protection and are continuing to evaluate the costs associated with their cleanup. There are uncertainties associated with these costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. We also continue to face possible liability as a potentially responsible party in the cleanup of ten multi-party hazardous waste sites in Massachusetts and other states where we are alleged to have generated, transported or disposed of hazardous waste at the sites. At the majority of these sites we are one of many potentially responsible parties and we currently expect to have only a small percentage of the potential liability. Through December 31, 1994, we have accrued approximately $7 million related to our cleanup liabilities. We are unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount, although based on our assessments of the specific site circumstances, we do not expect any such additional costs to have a material impact on our financial condition. However, additional provisions for cleanup costs could have a material impact on our results of a reporting period.

Note L. Long-Term Power Contracts

1. Long-Term Contracts for the Purchase of Electricity

We purchase electric power under several long-term contracts for which we pay a share of the generating unit's capital and fixed operating costs through the contract expiration date. The total cost of these contracts is included in purchased power expense in our consolidated income statements. Information relating to these contracts as of December 31, 1994 is as follows:

				proportionate share (in thousands)		
Generating Unit	Contract Expiration Date	Units of Capacity Purchased[a] %	MW	1994 Minimum Debt Service	1994 Interest Portion of Minimum Debt Service	Debt Outstanding Through Cont. Exp. Date
Canal Unit 1	2001	25.0	140	$ 796	$ 321	$ 1,928
Mass. Bay Transportation Authority	2005	100.0	34	(b)	(b)	(b)
Connecticut Yankee Atomic	2007	9.5	55	2,607	1,695	14,678
Ocean State Power - Unit 1	2010	23.5	67.5	5,072	3,653	21,563
Ocean State Power - Unit 2	2011	23.5	67.5	4,266	3,223	18,316
Northeast Energy Associates	(c)	(c)	219	(c)	(c)	(c)
L'Energia	2013	73.0	64	(d)	(d)	(d)
MassPower (e)	2013	44.3	117	12,642	8,088	86,538
Total			764	$25,383	$16,980	$143,023

(a) The Northeast Energy Associates contract represents 6.4% of our total system generation capability. The remaining units listed above represent 15.9% in total.

(b) We are required to pay the greater of $22.00 per kilowatt-year or 90% of the New England Power Pool capability responsibility adjustment charge up to $63.00 per kilowatt-year times the qualified capacity (currently rated at 34MW) plus incremental operating, maintenance and fuel costs. The total charges for this contract in 1994 were approximately $2 million.

(c) We purchase approximately 75.5% of the energy output of this unit under two contracts. One contract represents 135MW and expires in the year 2015. The other contract is for 84MW and expires in 2010. We pay for this energy based on a price per kWh actually received. We do not pay a proportionate share of the unit's capital and fixed operating costs. The total charges for these contracts in 1994 were approximately $119 million.

(d) We pay for this energy based on a price per kWh actually received. The total charges under this contract for 1994 were approximately $31 million.

(e) The MassPower contract started in January 1994. Payments are based on a stipulated price per MW rating of the unit subject to the unit maintaining a twelve month average availability of at least 90%. Payments are adjusted proportionately if the twelve month average is below 90%. If the twelve month average is less than 10% no payment is required. Total charges for this contract in 1994 were approximately $47 million.

Our total fixed and variable costs for these contracts in 1994, 1993 and 1992 were approximately $286 million, $225 million and $217 million, respectively. Our minimum fixed payments under these contracts for the years after 1994 are as follows:

(in thousands)	
1995	$ 105,574
1996	108,187
1997	105,622
1998	109,837
1999	108,196
Years thereafter	1,318,008
Total	$1,855,424
Total present value	$ 928,594

2. Long-Term Power Sales

In addition to our power sales to five wholesale customers, we sell a percentage of Pilgrim Station's output to other utilities under long-term contracts. Information relating to these contracts is as follows:

Contract Customer	Contract Expiration Date	Units of Capacity Sold %	Units of Capacity Sold MW
Commonwealth Electric Company	2012	11.0	73.7
Montaup Electric Company	2012	11.0	73.7
Various municipalities	2000(a)	3.7	25.0
Total		25.7	172.4

(a) Subject to certain adjustments.

Under these contracts, the utilities pay their proportional share of the costs of operating Pilgrim Station and associated transmission facilities. These costs include operation and maintenance expenses, insurance, local taxes, depreciation, decommissioning and a return on capital.

Selected Consolidated Quarterly Financial Data (Unaudited)

(in thousands, except earnings per share)

	Operating Revenues	Operating Income	Net Income	Balance Available for Common Stock	Earnings Per Average Common Share
1994					
First quarter	$377,449	$45,795	$19,812	$15,850	$0.35
Second quarter	368,655	50,395	23,982	20,031	0.44
Third quarter	449,094	96,599	70,182	66,256	1.46
Fourth quarter	353,356	34,034	11,046	7,120	0.16
1993					
First quarter	$354,752	$41,722	$15,452	$11,377	$0.25
Second quarter	346,074	49,282	22,829	19,125	0.43
Third quarter	436,024	96,319	70,015	66,053	1.47
Fourth quarter	345,403	37,996	9,922	5,958	0.13

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

Not applicable.

Part III

Item 10. Directors and Executive Officers of the Registrant

(a) Identification of Directors

See "Election of Directors - Information about Nominees and Incumbent Directors" on pages 1 through 4 of the definitive proxy statement dated March 27, 1995, incorporated herein by reference.

(b) Identification of Executive Officers

The information required by this item is included at the end of Part I of this Form 10-K under the caption Executive Officers of the Registrant.

Information regarding delinquent filers pursuant to Item 405 of Regulation S-K is included under "Stock Ownership by Directors and Executive Officers" on pages 4 through 5 of the definitive proxy statement dated March 27, 1995, incorporated herein by reference.

(c) Identification of Certain Significant Employees

Not applicable.

(d) Family Relationships

Not applicable.

(e) Business Experience

For information relating to the business experience during the past five years and other directorships (of companies subject to certain SEC requirements) held by each person nominated to be a director, see "Election of Directors - Information about Nominees and Incumbent Directors" on pages 1 through 4 of the definitive proxy statement dated March 27, 1995, incorporated herein by reference.

For information relating to the business experience during the past five years of each person who is an executive officer, see Executive Officers of the Registrant in this Form 10-K.

(f) Involvement in Certain Legal Proceedings

Not applicable.

(g) Promoters and Control Persons

Not applicable.

Item 11. Executive Compensation

See "Director and Executive Compensation" on pages 5 through 11 of the definitive proxy statement dated March 27, 1995, incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a) Security Ownership of Certain Beneficial Owners

To the knowledge of management, no person owns beneficially more than five percent of the outstanding voting securities of the Company.

(b) Security Ownership of Management

See "Stock Ownership by Directors and Executive Officers" on pages 4 through 5 of the definitive proxy statement dated March 27, 1995, incorporated herein by reference.

(c) Changes in Control

Not applicable.

Item 13. Certain Relationships and Related Transactions

Not applicable.

Part IV

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

Financial statement schedules have been omitted as they are either not required or not applicable.

		Exhibit	SEC Docket
Exhibit 3	**Articles of Incorporation and By-Laws**		
Incorporated herein by reference:			
3.1	Restated Articles of Organization	3.1	1-2301 Form 10-Q for the quarter ended June 30, 1994
3.2	Boston Edison Company Bylaws April 19, 1977, as amended January 22, 1987, January 28, 1988, May 24, 1988 and November 22, 1989	3.1	1-2301 Form 10-Q for the quarter ended June 30, 1990
Exhibit 4	**Instruments Defining the Rights of Security Holders, Including Indentures**		
Incorporated herein by reference:			
4.1	Medium-Term Notes Series A - Indenture dated September 1, 1988, between Boston Edison Company and Bank of Montreal Trust Company	4.1	1-2301 Form 10-Q for the quarter ended September 30, 1988
4.1.1	First Supplemental Indenture dated June 1, 1990 to Indenture dated September 1, 1988 with Bank of Montreal Trust Company - 9 7/8% debentures due June 1, 2020	4.1	1-2301 Form 8-K dated June 28, 1990
4.1.2	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken December 11, 1990 re 8 7/8% debentures due December 15, 1995	4.1	1-2301 Form 10-Q for the quarter ended March 31, 1991
4.1.3	Indenture of Trust and Agreement among the City of Boston, Massachusetts (acting by and through its Industrial Development Financing Authority) and Harbor Electric Energy Company and Shawmut Bank, N.A., as Trustee, dated November 1, 1991	4.1.26	1-2301 Form 10-K for the year ended December 31, 1991

		Exhibit	SEC Docket
4.1.4	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken August 5, 1991 re 9 3/8% debentures due August 15, 2021	4.1.27	1-2301 Form 10-K for the year ended December 31, 1991
4.1.5	Revolving Credit Agreement dated February 12, 1993	4.1.24	1-2301 Form 10-K for the year ended December 31, 1992
4.1.6	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken September 10, 1992 re 8 1/4% debentures due September 15, 2022	4.1.25	1-2301 Form 10-K for the year ended December 31, 1992
4.1.7	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken January 27, 1993 re 6.80% debentures due February 1, 2000	4.1.26	1-2301 Form 10-K for the year ended December 31, 1992
4.1.8	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken March 5,1993 re 5 1/8% debentures due March 15, 1996, 5.70% debentures due March 15, 1997, 5.95% debentures due March 15, 1998, 6.80% debentures due March 15, 2003, 7.80% debentures due March 15, 2023	4.1.27	1-2301 Form 10-K for the year ended December 31, 1992
4.1.9	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken August 18, 1993 re 6.05% debentures due August 15, 2000	4.1.28	1-2301 Form 10-K for the year ended December 31, 1993

The Company agrees to furnish to the Securities and Exchange Commission, upon request, a copy of any agreements or instruments defining the rights of holders of any long-term debt whose authorization does not exceed 10% of the Company's total assets.

		Exhibit	SEC Docket
Exhibit 10	**Material Contracts**		
Incorporated herein by reference:			
10.1	Key Executive Benefit Plan (1982 Form of Agreement)	10.13	1-2301 Form 10-K for the year ended December 31, 1992
10.1.1	Amendment to Key Executive Benefit Plan dated February 1, 1986	10.4.1	1-2301 Form 10-K for the year ended December 31, 1985
10.1.2	Key Executive Benefit Plan Standard Form of Agreement, May 1986	10.1	1-2301 Form 10-Q for the quarter ended June 30, 1986
10.1.3	Key Executive Benefit Plan Standard Form of Agreement, May 1986, with modifications	10.3.1	1-2301 Form 10-K for the year ended December 31, 1991
10.2	Executive Annual Incentive Compensation Plan	10.5	1-2301 Form 10-K for the year ended December 31, 1988
10.3	1991 Director Stock Plan	10.1	1-2301 Form 10-Q for the quarter ended March 31, 1991

		Exhibit	SEC Docket
10.4	Boston Edison Company Deferred Fee Plan dated January 1, 1990	10.11	1-2301 Form 10-K for the year ended December 31, 1992
10.5	Deferred Compensation Trust between Boston Edison Company and State Street Bank and Trust Company dated February 2, 1993	10.10	1-2301 Form 10-K for the year ended December 31, 1992
10.6	Directors Retirement Benefit (1993 Plan)	10.8.1	1-2301 Form 10-K for the year ended December 31, 1993

Filed herewith:

10.5.1	Amendment No. 1 to Deferred Compensation Trust dated March 31, 1994
10.7	Description of Supplemental Fee Arrangement for Certain Directors
10.8	Performance Share Plan, Amendment and Restatement dated October 24, 1994
10.9	Boston Edison Company Deferred Compensation Plan, Amendment and Restatement dated January 31, 1995
10.10	Employment Agreement applicable to Ronald A. Ledgett dated April 30, 1987

		Exhibit	SEC Docket
10.11	Description of Compensation Arrangement with Bernard W. Reznicek dated June 23, 1994		

Exhibit 12 Statement re Computation of Ratios

Filed herewith:

12.1	Computation of Ratio of Earnings to Fixed Charges for the Year Ended December 31, 1994		
12.2	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements for the Year Ended December 31, 1994		

Exhibit 18 Letter re Change in Accounting Principle

Incorporated herein by reference:

18.1	Letter of Independent Certified Public Accountants	18.1	1-2301 Form 10-Q for the quarter ended March 31, 1990

Exhibit 21 Subsidiaries of the Registrant

21.1	Harbor Electric Energy Company (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Edison Company		
21.2	Boston Energy Technology Group, Inc. (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Edison Company		
21.3	Ener-G-Vision, Inc. (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Energy Technology Group, Inc.		
21.4	TravElectric Services Corporation (incorporated in Massachusetts), a wholly-owned subsidiary of Boston Energy Technology Group, Inc.		

		Exhibit	SEC Docket
21.5	REZ-TEK International Corporation (incorporated in Massachusetts), a majority-owned subsidiary of Boston Energy Technology Group, Inc.		
21.6	Coneco Corporation (incorporated in Massachusetts), a majority-owned subsidiary of Boston Energy Technology Group, Inc.		

Exhibit 23 Consent of Independent Accountants

Filed herewith:

23.1	Consent of Independent Accountants to incorporate by reference their opinion included with this Form 10-K in the Form S-3 Registration Statements filed by the Company on September 14, 1990 (File No. 33-36824), February 3, 1993 (File No. 33-57840) and in the Form S-8 Registration Statements filed by the Company on October 10, 1985 (File No. 33-00810), July 28, 1986 (File No. 33-7558), December 31, 1990 (File No. 33-38434), June 5, 1992 (33-48424 and 33-48425) and March 17, 1993 (33-59662 and 33-59682).		

Exhibit 27 Financial Data Schedule

Filed herewith:

27.1	Schedule UT		

Exhibit 99 Additional Exhibits

Incorporated herein by reference:

99.1	DPU Settlement Agreement with Boston Edison Company dated October 3, 1989	28.1	1-2301 Form 8-K dated October 3, 1989

		Exhibit	SEC Docket
99.2	Settlement Agreement between Boston Edison Company and Commonwealth Electric Company, Montaup Electric Company and the Municipal Light Department of the Town of Reading, Massachusetts, dated January 5, 1990	28.1	1-2301 Form 8-K dated December 21, 1989
99.3	Pilgrim Outage Case Settlement between Boston Edison Company and Reading Municipal Light Department regarding Contract Demand Rate, dated December 21, 1989	28.2	1-2301 Form 8-K dated December 21, 1989
99.4	Settlement Agreement Between Boston Edison Company and City of Holyoke Gas and Electric Department et. al., dated April 26, 1990	28.2	1-2301 Form 10-Q for the quarter ended March 31, 1990
99.5	Information required by SEC Form 11-K for certain Company employee benefit plans for the years ended December 31, 1993, 1992 and 1991		1-2301 Form 10-K/A Amendment to Form 10-K for the year ended December 31, 1993 and Form 8 Amendments to Form 10-K for the years ended December 31, 1992 and 1991, dated June 30, 1994, June 29, 1993 and June 26, 1992, respectively
99.6	DPU Settlement Agreement with Boston Edison Company, dated October 23, 1992	28.2	1-2301 Form 10-Q for the quarter ended September 30, 1992

(b) Reports on Form 8-K

There were no Form 8-K's filed during the fourth quarter of 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.

BOSTON EDISON COMPANY

By: /s/ Charles E. Peters, Jr.
Charles E. Peters, Jr.
Senior Vice President - Finance
(Principal Financial Officer)

Date: March 23, 1995

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 indicated on the 23rd day of March 1995.

/s/ Thomas J. May Thomas J. May	Chairman of the Board and Chief Executive Officer
/s/ George W. Davis George W. Davis	President and Chief Operating Officer and Director
/s/ Robert J. Weafer, Jr. Robert J. Weafer, Jr.	Vice President, Controller and Chief Accounting Officer
/s/ William F. Connell William F. Connell	Director
/s/ Gary L. Countryman Gary L. Countryman	Director
Thomas G. Dignan, Jr.	Director
Charles K. Gifford	Director
/s/ Nelson S. Gifford Nelson S. Gifford	Director

/s/ Kenneth I. Guscott Kenneth I. Guscott	Director
/s/ Matina S. Horner Matina S. Horner	Director
/s/ Sherry H. Penney Sherry H. Penney	Director
/s/ Bernard W. Reznicek Bernard W. Reznicek	Director
/s/ Herbert Roth, Jr. Herbert Roth, Jr.	Director
____________________ Stephen J. Sweeney	Director
____________________ Paul E. Tsongas	Director

Report of Independent Accountants

To the Stockholders and Directors of Boston Edison Company:

We have audited the consolidated financial statements of Boston Edison Company and subsidiaries (the Company) listed in Item 14(a) of this Form 10-K. These consolidated 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 1994 and 1993, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

Boston, Massachusetts
January 26, 1995