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

Boston Edison

Pilgrim Nuclear Power Station
Rocky Hill Road
Plymouth, Massachusetts 02360

Henry V. Oheim
General Manager - Technical Section

April 10, 1996
BECo Ltr. #96-031

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

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

Annual Financial Statement for 1995

In accordance with 10CFR 50.71(b) and 10CFR 140.15(b)(1), Boston Edison submits the enclosed 1995 annual report and the Securities and Exchange Commission (SEC) Form 10-K which corresponds to the 1995 annual report.

If you have any questions on this documentation, please contact Mr. Robert Cannon at (508) 830-8321.

William R. Kline for

H. V. Oheim

RLC/Rap95/10K-94

Attachment

cc: Mr. R. Eaton, Project Manager
Division of Reactor Projects - I/II
Mail Stop: 14D1
U. S. Nuclear Regulatory Commission
1 White Flint North
11555 Rockville Pike
Rockville, MD 20852

U.S. Nuclear Regulatory Commission
Region I
475 Allendale Road
King of Prussia, PA 19406

Senior Resident Inspector
Pilgrim Nuclear Power Station

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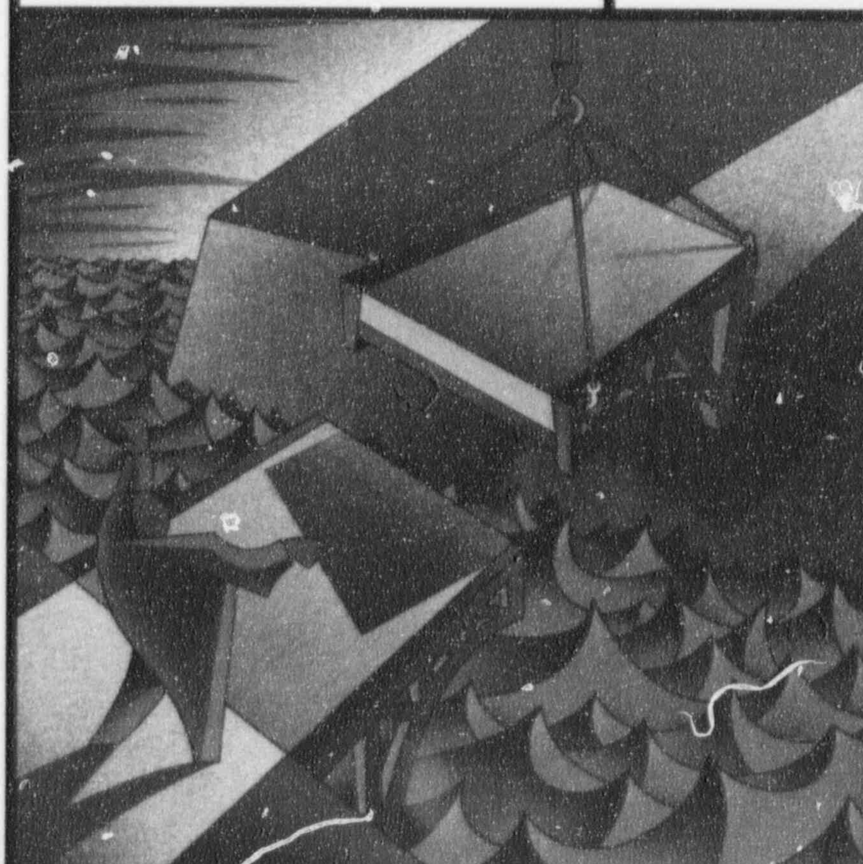
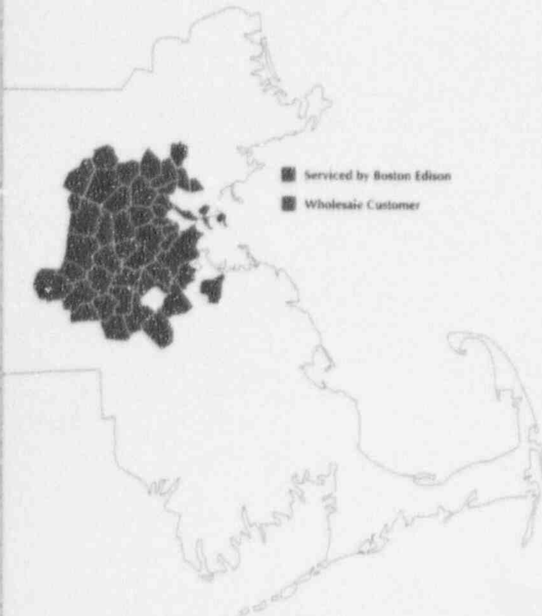
1995 Annual Report To Shareholders



Boston Edison



About The Company

Boston Edison is a public utility engaged principally in the generation, purchase, transmission, distribution and sale of electric energy. It was incorporated in 1886. We supply electricity at retail to an area of approximately 590 square miles within 30 miles of Boston, encompassing the City of Boston and 39 surrounding cities and towns. The population of the territory served at retail is approximately 1,500,000.

We also supply electricity to other utilities and municipal electric departments at wholesale for resale. About 87 percent of our revenues are derived from retail electric sales, 11 percent from wholesale sales and 2 percent from other sources.

Financial Highlights

	years ended December 31, 1995		1994
Operating revenues (000)	**$1,628,503**		$1,544,735
Income available for common stock (000)	**$96,739**		$109,257
Common shares outstanding - weighted average (000)	**46,592**		45,338
Common stock data:			
Earnings per share (excluding restructuring charge)	**$2.52**	(a)	$2.41
Dividends declared per share	**$1.835**		$1.775
Payout ratio (excluding restructuring charge)	**72 %**	(a)	73 %
Book value per share	**$20.61**		$20.11
Return on average common equity (excluding restructuring charge)	**12.2 %**	(a)	12.1 %
Fixed charge coverage (SEC)	**2.38**		2.46

Certain reclassifications and recalculations were made to the data reported in the prior year to conform to the method of presentation used in 1995.

(a) The company incurred a $0.44 per share restructuring charge in 1995.

Above, Boston Mayor Tom Menino and Tom May announce the company's contribution of money, computer hardware and volunteers to the Boston School Department in support of the Mayor's educational initiative.

On The Cover: Crossing the bridge to competition. Boston Edison will continue to focus on its customers and its communities as it helps drive and shape industry reform.

1995 Annual Report To Shareholders

Dear Shareholder,

Nineteen ninety-five was an eventful, historic year in the electric utility industry, with at least 40 states looking at various aspects of deregulation. **Here in Massachusetts, Boston Edison has been among the leaders in shaping industry reform and will continue as a powerful influence.** As we help shape the future of the industry, Boston Edison will continue to balance the interests of consumers and shareholders, steadily navigating the choppy waters of industry reform from a position of financial strength. Customer relationships are being forged in this new environment, and new opportunities in two-way customer communications are being pursued. We continue as a full-service utility while offering many nontraditional products and services.

This past year was a transition year, by all accounts, as the move to restructure gained momentum. Key issues were addressed by regulators, utilities, communities, consumers, environmentalists and independent power producers alike. In last year's Annual Report, your company described the issues surrounding industry reform and Boston Edison's strategic direction to address them.

The clear direction of public policy is to unbundle utility operations. Boston Edison is moving in parallel with this trend, reshaping and redefining the company as well. Internally, we continue to cut costs, streamline the company and increase overall services to the customer. Because of these efforts, we delivered another strong year of financial performance.

Our dividend growth for 1995 was within the top 15 percent of the industry. We declared a six-cent dividend increase in December 1995, bringing the annual rate to $1.88 per share, a 3.3 percent increase. This is at a time when more than half of the nation's electric utilities are decreasing or levelizing their dividends. Our earnings for 1995 were $2.52, not including a $0.44 accounting charge related to our corporate restructuring. This represents a 4.6 percent increase over last year. Return on equity remains strong at 12.2 percent versus last year's 12.1 percent (again excluding the restructuring charge). **Our three-year total return on investment is the highest of the major New England utilities.**

The strength of our stock price steadily improved throughout 1995, trending up from $24 per share at the beginning of the year, and closing at $29-1/2 at year-end. Our equity ratio also improved in 1995 to its strongest level in a decade, primarily due to new common stock issued during the year.

We also performed well operationally. Average service restoration times improved by 15 percent and more than 90 percent of all new services were installed within a three-day turnaround. The company's aging distribution system, including the downtown network, is being upgraded for increased reliability. Additionally, the company's fossil generating units achieved the second best performance in history for unit availability. In nuclear generation, Pilgrim Station surpassed all previous capacity factors during a refueling outage year and recently set a new record for continuous operation.

INDUSTRY PICTURE — THE MASSACHUSETTS DEBATE

Customers will benefit from the forces of competition as the electric utility industry moves to restructure. Under the regulatory model, Boston Edison, like most utilities, was fully integrated, manufacturing the product of electricity, and handling the transmission and distribution of that product to its customers.

Boston Edison's vision of a restructured industry is one in which educated consumers choose freely among competitors for their energy supply and services. In the new environment, the three major components of the business will be separated. Electricity generation will become totally deregulated over time. Kilowatts will become a commodity, sold at the market price. All generators and users will have equal access to the transmission system and will pay the same charge to move their products along this "transmission highway." Distribution, or electricity delivery, will still be highly regulated, but distribution companies will have opportunities to offer new product lines and expanded services. Over time, our own distribution business will develop into a full client/service network. It will offer interactive communications with customers that will help them get the best price for their energy and use that energy more efficiently.

Clearly, the industry is moving toward direct access and lower energy costs. Customers will first see their bills simplified, showing production and delivery charges separately. These bills will have fewer components and an easier-to-understand format that will help clarify energy usage. As customers learn about the market through these new pricing signals, they will increasingly look for the best energy market price and related products and services. Boston Edison will be there to package those retail services for customers.

But there are many issues requiring joint resolution by interested parties before total deregulation can occur. One major issue is stranded cost recovery. Those costs represent investments made to meet regulatory obligations. There are several positive signs that indicate stranded costs will be handled in a fair and equitable way. The Federal Energy Regulatory Commission's actions on transmission access provide for a reasonable opportunity to recover investments, as did the Massachusetts Department of Public Utilities in its August 16, 1995, order. **In terms of Boston Edison's own stranded cost exposure, we are positioned well in relation to other New England utilities.** We are not waiting, however, for a final ruling on stranded cost recovery to clean up our balance sheet. Cost savings are already being rechanneled to mitigate the potential for stranded costs.

Professor William Hogan is Research Director of the Harvard Electricity Policy Group at the Kennedy School of Government, Harvard University. Professor Hogan, a leading national authority on industry restructuring, has been a supporter of the company's E-Plan approach.

In the meantime, we were the first to submit our own restructuring plan, the E-Plan, which is the quickest path to lower prices and customer choice. Under the E-Plan, all customers could choose their energy suppliers as early as 1998. However, the E-Plan includes an invaluable transition element. It unbundles utility costs, sets performance incentives for pricing delivery, simulates market prices for production, and, perhaps more importantly, educ. .s consumers. All of this can begin in 1997, at least one full year earlier than the start of most other restructuring plans.

Beyond all this debate, customers, both large and small, want to know when tangible results will be seen, when prices will drop substantially. Boston Edison believes competitive prices benefit everyone. It is important to note that the trend toward lower costs has already begun. **In inflation-adjusted terms, Boston Edison customers are paying 25 percent less per kilowatt-hour today than they did in 1981.** More significant price changes will be seen in the coming years.

CROSSING THE BRIDGE — BOSTON EDISON'S COMPETITIVE STRATEGY

In anticipation of the new competitive model, Boston Edison announced last July the formation of Business Units, one month before the DPU announced its plan to restructure the industry. This is an internal alignment to the unbundling concept, giving profit and service responsibilities as well as operational accountabilities to various segments of our business. These segments include Fossil, Nuclear, Customer and Corporate Services.

The company's Organization Future Project, which led to the formation of these Business Units, focused on reducing staffing and management layers, as well as speeding decision making and providing quicker customer response. By year-end 1996, we will have 3,400 employees. This is the lowest employment level since 1950, yet we now service twice the customer base and carry more than five times the load we had 45 years ago. **Boston Edison's commitment, as with all successfully deregulated companies, is to reduce costs, increase revenues and enhance service simultaneously.** Through redefining practices and procedures as well as using new technology, we are meeting this aggressive challenge. We reduced management ranks by nearly 40 percent in 1995, eliminating two management layers, redefining the remaining management positions and reselecting managers based on new skills and competencies.

This restructuring will reduce our costs by approximately $30 million a year, and these savings can be applied to reduce our stranded investment exposure while continuing our strong financial performance. Additionally, the restructuring has resulted in an even stronger, more dynamic leadership team.

Boston Edison employees dealt effectively with these dramatic changes. This was the most significant staffing reduction in the company's history. Throughout the process, employees demonstrated professionalism, business savvy and concern for the company's future. New work processes, enhanced teamwork and innovative thinking will continue to help us stay ahead of industry developments.

THE CUSTOMER STORY

There is much more to the company's success than just cutting costs. Boston Edison is protecting and growing revenues through enhanced customer focus. We already face competition in several forms, vying with power marketers and other utilities to retain and attract customers. **One way Boston Edison will succeed is to help customers succeed in their respective businesses. We offer much more than a mere commodity to our customers.** We are providing total energy solutions, not only quality energy but value-added services and customized approaches to a customer's individual energy needs.

For example, Boston Edison recently signed a long-term agreement with one of its largest wholesale customers, the Massachusetts Port Authority (Massport). During the life of this contract, the Authority's electricity use will more than double. Boston Edison provided Massport with a competitive price and services to meet its growing demand. It is this kind of integrated approach that will position us as one of the most responsive, service-oriented energy suppliers in the region — and the one with the best overall value.

Our track record is impressive. There have been some half dozen major competitive situations in the last few years. **We squared off with our competitors — including major utilities in the region — and won every bid.**

NEW BUSINESS OPPORTUNITIES

In addition to retaining and growing a strong customer base, we are also looking at new revenue. Boston Edison already offers an array of new products and services, including power systems services, power quality consulting and conservation services. Through the company's unregulated subsidiary, Boston Energy Technology Group (BETG), we have had success in the energy services business with clients in Florida, the Midwest and New England. Coneco, the subsidiary's energy services management company, saw 1995 revenues of $6.2 million, with annual growth projected at more than 50 percent.

BETG also announced recently the formation of a joint venture for district cooling in downtown Boston. The joint venture, Northwind-Boston, with Unicom Thermal Technologies,

is attractive because it provides commercial customers with a clean and efficient alternative for cooling buildings. Over the next five years, this project is expected to generate about $15 million in annual revenue. It will be an important value-added service for customer retention and also will help us gain marketshare.

CLEAR VISION OF THE FUTURE

Boston Edison will continue to help shape the evolving, competitive market and will pursue a leadership role in the development of a cohesive industry restructuring plan for Massachusetts. Competitors in this new arena will require a different set of skills and attitudes to survive and thrive. **Your company's leadership and employees have what is necessary to succeed** and, as yo' ıl see throughout the balance of this report, are exercising those skills daily for the benefit of shareholders, customers and the communities we serve.

Our financial performance relative to the rest of the industry is strong. Our internal structure, dedicated employees and external influence will guide our success in the restructured industry. Boston Edison is crossing the threshold, not with misgivings but rather with complete confidence.

Thomas J. May

Tom May

Chairman, President and Chief Executive Officer

Industrial and Manufacturing *While Boston Edison's industrial base is relatively small, amounting to about 12 percent of retail sales, its associated manufacturing jobs are valuable to the region. Despite the manufacturing decline in recent years, there are success stories and your company has played a part in many of them.*

In tandem with substantial State efforts to provide incentives for manufacturing in Massachusetts, Boston Edison's own economic development efforts resulted in 28 megawatts of new and retained load, representing more than $6 million in annual base revenue. These results were recently recognized when Chairman, President and CEO Tom May was named Chairman of the Governor's Council on Economic Growth and Technology.

EMC's Dan Fitzgerald at the Hopkinton manufacturing facility.

EMC Corporation

As a manufacturer of data storage devices, Hopkinton-based EMC Corporation has enjoyed record sales and has been the fastest growing company in Massachusetts two years running. EMC recently surpassed IBM for the No. 1 position in the mainframe storage market, just five years after they entered that market, making it a challenge to keep pace with burgeoning demand.

EMC also is an industry leader in quality control. Every unit they produce undergoes rigorous testing before it is shipped to a client.

EMC's rapid growth and demand for product quality are where Boston Edison enters the picture. Sensitive testing equipment requires much more than just an on/off switch for electricity. Even a small power dip is a serious power quality issue at EMC because their product is continuously tested in a 21-day cycle. That means EMC sets very high expectations for their energy supplier.

The EMC/Boston Edison partnership goes back to 1990. We have installed ice storage, lighting and cooling equipment at EMC as part of our Energy Efficiency Partnership. EMC also benefited from an Economic Development Rate for load expansion within our service territory.

Working in tandem with EMC, we ensure that the quality of *our* product enhances the quality of *theirs*. To do that, we had to first understand the specific needs of this fast-growing, highly-successful company.

Currently a 9-megawatt customer, EMC's rapid expansion will increase their load by 100 percent over the next five years. Both Boston Edison and EMC recognized that, to meet this growth, the delivery system in the area needed to be upgraded. To that end, Boston Edison, EMC and the town of Hopkinton are cooperating to fast-track construction of a new substation. Instead of the normal four to five years from concept to operation, this new substation will be completed in just two years. Additionally, dedicated circuits were run to EMC's main facility to ensure greater reliability and better overall power quality for this valued customer.

"Boston Edison has been committed to making all improvements necessary to supply EMC reliably," said EMC's Director of Corporate Facilities Dan Fitzgerald. "Boston Edison's electric customer service and engineering staff undertook a remarkable effort in constructing dedicated and back-up supplies to our main manufacturing facility. This will solidify our partnership and ensure our mutual success."

As EMC's business continues to grow and evolve, Boston Edison will be there, listening and responding. We will work to understand this customer's changing needs, to apply our expertise in solving their energy problems and to offer innovative energy-related services that will enhance their business operations.

Commercial and Government *The commercial sector, which includes government customers, remains the cornerstone of the company's business, representing over 59 percent of retail sales. The area's economy showed slow but sustained growth in 1995. That was especially noticeable in the improving occupancy rates of commercial buildings. For the first time in several years, new commercial projects were announced. High technology and financial services companies continued to add employees despite cutbacks in the health and banking sectors.*

The company works with commercial/government customers to tailor solutions and meet their unique needs.

Massport's Steve Tocco at Logan International Airport.

Massport

The Massachusetts Port Authority (Massport) is one of Boston Edison's largest and most valued wholesale customers. As the operator of Boston's Logan Airport and four other locations, Massport has vast electrical energy needs, **with a current load of 25 megawatts that is expected to more than double over the next decade.** Massport decided last year to test the competitive waters for suppliers. Boston Edison was involved with each new option Massport explored, providing innovative ideas to meet their energy issues.

Boston Edison recently reached a ten-year agreement with Massport after fierce competition with ten other suppliers. **The long-term agreement between Boston Edison and Massport will bring the Port Authority into the 21st century,** with energy efficiency measures and operational improvements. More predictable, stable energy prices were negotiated in recognition of the significant growth Massport will experience.

With increased competition in the electric power industry, Massport anticipated that this was the proper time to lock in savings through a long-term contract. The agreement is an acknowledgment of the Authority's huge demand for electricity and Boston Edison's desire to forge a relationship that will endure in the emerging energy marketplace.

"We selected Boston Edison from a pool of 11 proposals from major utilities — some as far away as Texas," said Massport Executive Director Stephen P. Tocco. "But when Massport evaluated the proposals according to price, experience in the power generating market and quality of generating capacity, Boston Edison's proposal was determined to be the best for the Authority. We are ecstatic to be staying with Boston Edison, a local company which has served the Authority's needs for many years."

Also under this agreement, Massport and Boston Edison will expand their pilot program for using electric vehicles (EVs) at Logan, with plans to make the airport an EV showcase.

Boston Edison also will provide a comprehensive package of energy efficiency measures at Massport, including switchgear maintenance services and the installation of efficient electric chillers to replace existing steam absorbers throughout the Massport system.

FleetCenter's Chris Maher joins thousands of comfortable spectators for a Friday night game.

FleetCenter

A source of great pride to the City of Boston, FleetCenter opened in grand style last September. This 775,000-square-foot sports and entertainment complex puts an emphasis on spectator comfort and overall efficiency. Boston Edison played a key role in FleetCenter's design by installing energy-efficient technologies expected to cut energy costs by about $60,000 a year.

High-efficiency chillers, motors and lighting along with variable speed drives on all major air handling equipment will reduce the facility's annual consumption by over 620,000 kilowatt-hours. All these measures contribute greatly to the comfort and enjoyment of spectators.

While the Boston Garden was an historic landmark, it was the oldest operating facility of its kind in the country. **No longer will fans have to endure sweltering temperatures at a Celtics game or fog on the ice at a Bruins game.** The new FleetCenter arena is a year-round facility that can attract summer sporting and entertainment events as well as large conventions and corporate meetings. Its appeal is due, in large part, to proper cooling systems.

Edison engineers worked with developers to incorporate upgrades into the overall design and worked with an aggressive schedule, completing the work on time and within budget. With a 4- to 5-megawatt load at the arena, the upgrades will go a long way toward keeping costs under control.

"The quality of the relationship with Boston Edison is first-rate," says FleetCenter Vice President of Operations Chris Maher. "I can call our Edison representative anytime to get help with cost estimating and budget preparation. They are introducing new ideas for better cost control all the time. Boston Edison is a resource for any energy problem we encounter and we look to them for professional solutions."

FleetCenter is indeed a showplace with superior acoustics, unobstructed views, a state-of-the-art JumboTron scoreboard and, of course, cutting-edge lighting and climate control. Add to that a host of other amenities, and you have a world-class facility.

U. S. Olympic Gymnastic Trials are coming to FleetCenter in June, an event that was made possible by having a four-season facility. While the Boston Garden will hold fond memories of such legends as Bill Russell, Bobby Orr, Larry Bird and Johnny Most, FleetCenter will soon have its own legends. Boston Edison is proud to be part of it.

Residential/Community *Residential customers are clearly stakeholders, but so, too, are the communities we serve and in which we operate. Boston Edison will continue to have a very large stake in the communities. The attitudes of residential customers, who account for about 28 percent of retail sales, and the company's relationship with communities are equally important to us.*

Listening, understanding and responsiveness are the attributes which allow a company to meet the needs of residential customers and community leaders. To this group, we add our small commercial customers, especially those who work and live in the neighborhoods we service.

John O'Neill of the Consumer Advisory Panel visits Boston Edison's Meter Test Lab.

Mary Mulvey Jacobson represents the concerns of the West Roxbury business community, like the West Roxbury Pub and Restaurant, a cornerstone establishment in the neighborhood.

Consumer Advisory Panel

Boston Edison's Consumer Advisory Panel serves as a focus group for customer-related ideas and concerns. John O'Neill serves in his fourth year on the panel and is currently co-chair.

"It's a great feeling to know you're having meaningful input on behalf of hundreds of thousands of customers," he said. **"The panel can talk to Boston Edison management at the top levels and get results."**

The Consumer Advisory Panel provides feedback and guidance from a consumer standpoint on several key issues, including industry deregulation, system modernization, energy efficiency and environmental concerns. Additionally, the panel has monitored calls in Boston Edison's Customer Call Center. "The panel is impressed with the response to customer inquiries," O'Neill added. **"Edison representatives use a concerned and caring approach with customers and work to thoroughly resolve problems."**

But the single largest issue for the Consumer Advisory Panel has been accurate meter reading. "Meter reading is, by far, the issue of most importance to residential customers," O'Neill stressed, and he should know. Aside from serving as the panel's co-chair, he is also CEO/Executive Director for Somerville-Cambridge Elder Services.

"Clarity and accuracy of bills is important, not only to residential customers in general, but, in particular, to elderly customers. Some of my constituents would go without a meal in order to pay all their bills."

Boston Edison took that feedback seriously and is accelerating its automated meter reading strategy. Within the next 18 months, 260,000, or over one-third of Boston Edison's meters, will be replaced with automated meter devices, providing information from previously inaccessible meters. Soon to follow will be sophisticated customer devices capable of interactive, two-way communications.

These new technologies will result in more predictable, accurate bills. More importantly, they will improve energy management and create opportunities for new products and services.

West Roxbury

The center of West Roxbury is a booming commercial area with a full spectrum of small businesses operating there. As President of the West Roxbury Business and Professional Association, Mary Mulvey Jacobson represents the concerns of more than 250 small businesses and commercial property owners. Mulvey Jacobson helped Boston Edison enhance its relationship with the business community to ensure greater reliability for this growing commercial area.

Chief among these efforts was the development of a system upgrade plan that coordinated planned outages in the area for minimum impact on business owners.

"I was bowled over by the sensitivity of Edison's plan," said Mulvey Jacobson. "It showed that they were listening."

Boston Edison recently joined the West Roxbury Business and Professional Association, adding to its involvement in civic and business groups.

Marie Theodat (left) and Marie-Rose Romain Murphy of Codman Square Main Street join Boston Mayor Thomas Menino to survey the restoration of some spectacular neighborhood architecture. Formerly a public library, the building houses the Codman Square Health Center's executive offices as well as an event center and community youth program.

Main Street

Boston Edison is an active participant in the City of Boston's Main Street program, an effort to improve Boston's neighborhood commercial districts. This $4.2 million initiative is the largest, most all-encompassing of its kind in the country, offering assistance to more than 20 Boston communities. Boston Main Street is an innovative program that brings together resources from the Federal government, the City of Boston and local corporations to assist neighborhood commercial areas in their revitalization efforts. As a "Corporate Buddy," Boston Edison is working with Codman Square Main Street on the growth and economic development of that community.

Nationally, the concept has been implemented in more than 1,000 small communities and city neighborhoods. **What differentiates Boston's initiative is its city-wide implementation in a large urban area — a national first.** As a city councilor, Boston Mayor Thomas Menino was instrumental in bringing the program into his own Roslindale neighborhood a decade ago and has worked to expand the concept into a signature revitalization project. "As the neighborhood business goes, so goes the neighborhood," he said.

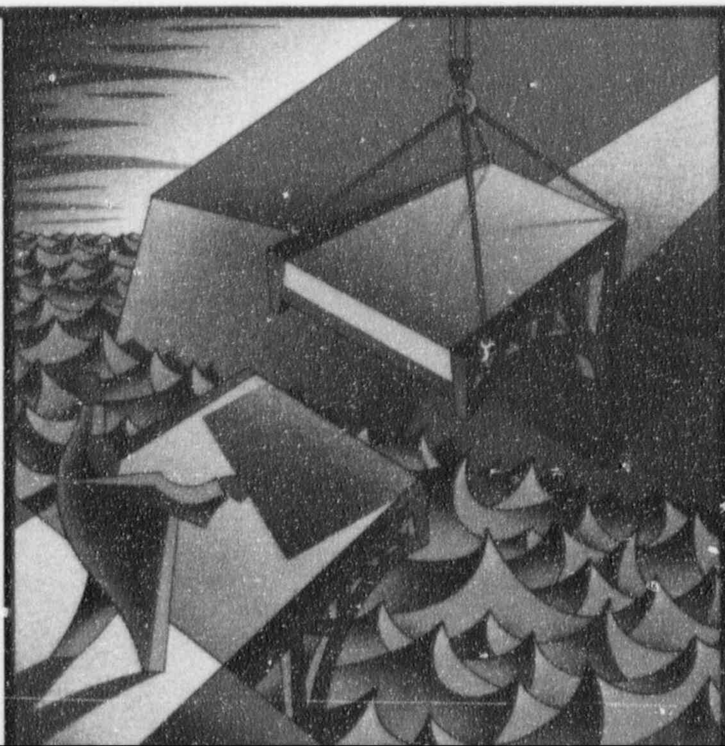
Boston Edison is one of several corporations awarding a $40,000 grant to its sponsor area. With that money, Codman Square Main Street hired an executive director and began a comprehensive marketing and economic improvement strategy.

"Boston Edison's commitment goes above and beyond financial support," says Marie-Rose Romain Murphy, executive director for Codman Square Main Street Inc. "We are thrilled with their willingness to provide us access to their resources such as technical assistance and in-kind services. Working with Edison will be key to the success of our organization and, ultimately, to Codman Square's growth and development."

Individuals representing the different sectors of the community comprise the Main Street Board, including merchants, residents, commercial property owners and local non-profit organizations. This group controls resources provided by the city and has helped to recruit 35 new businesses into the area. They also plan aggressive retail promotion as well as community festivals and events to draw potential customers to the area.

Financial Section

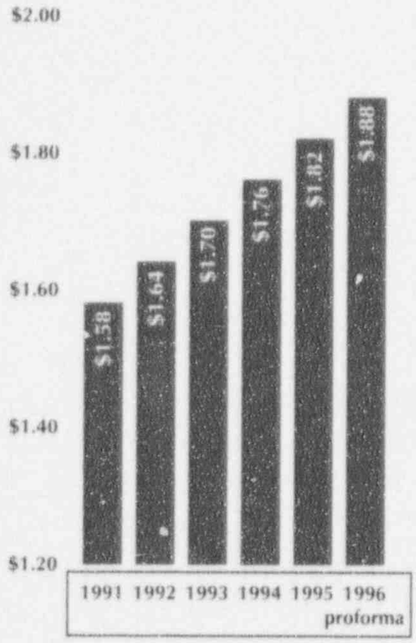
Contents



Company Highlights

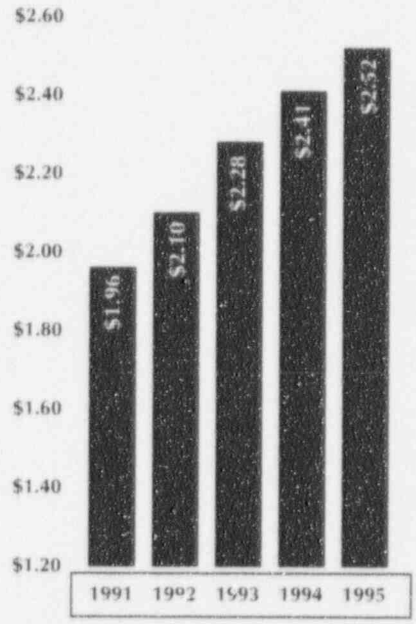
Dividends Paid Per Share

Increased on a percentage basis by more than industry average in each of the past five years.



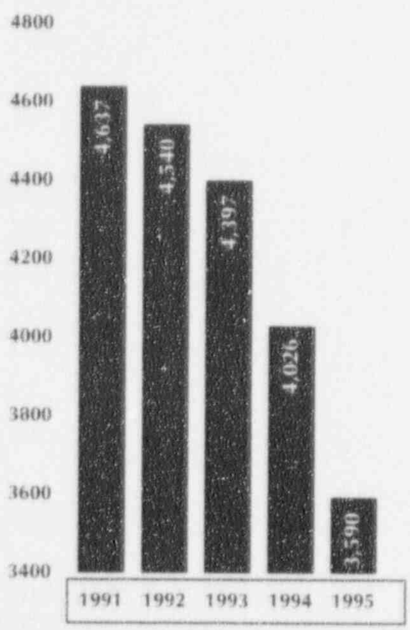
Earnings Per Share Excluding Restructuring

Continues to show steady increase. 1995 amount excludes a $0.44 restructuring charge.



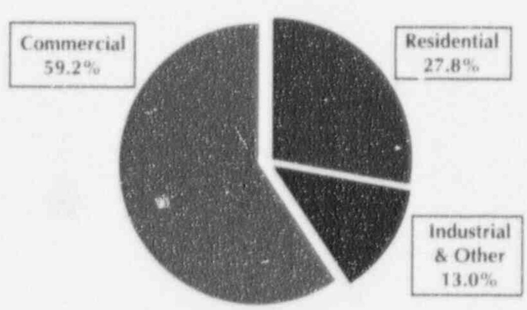
Number of Employees

Decreased 10.8%, in line with our plans to pare down to 3,400 employees by year-end 1996.



Retail Sales Mix

Stabilized by the commercial and residential sectors that help minimize effects of regional economic swings.



Management's Discussion and Analysis

Rate Regulation

The rates we charge our retail customers are regulated by our state regulators, the Massachusetts Department of Public Utilities (DPU). In 1992 the DPU 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 two annual base rate increases of $29 million effective November 1993 and November 1994 and an annual performance adjustment charge effective November 1992 through October 2000. The performance adjustment charge varies annually based on the performance of Pilgrim Nuclear Power Station. This charge is further described in the Electric Sales and Revenues section.

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.

We did not make a base rate filing upon the expiration of the 1992 settlement agreement, therefore base rates currently remain in effect at their 1995 levels.

In February 1996 we filed an industry restructuring plan with the DPU in response to its August 1995 order on restructuring the electric utility industry. This plan is expected to lead to negotiations with intervening parties that will result in an unbundling of our currently integrated monopoly business into a separate competitive electric production business and a regulated electric distribution business. Refer to Outlook for the Future for further information regarding the restructuring of the electric utility industry in Massachusetts.

Results of Operations

1995 versus 1994

Earnings per common share were $2.08 in 1995 and $2.41 in 1994. Earnings in 1995 reflect a one-time charge of $34 million ($20.7 million net of tax, or $0.44 per share) associated with our corporate restructuring. The charge reflects the costs of early retirement and severance programs implemented as part of our organizational streamlining and reorganization into business units. Excluding the one-time charge, earnings per common share were $2.52 in 1995, an increase of 4.6% over 1994. This increase is due to the $29 million annual retail base rate increase effective November 1994, the ending of amortization of deferred cancelled nuclear costs in 1994, a 1.2% increase in retail kWh sales and lower revenue reserve provisions. These positive impacts were partially offset by higher income tax, property tax, nuclear outage amortization and employee benefit expenses, and an award received on an eminent domain case in 1994.

Operating revenues

Operating revenues increased 5.4% over 1994 as follows:

(in thousands)	
Retail electric revenues	$59,419
Demand side management revenues	8,783
Wholesale and other revenues	11,126
Short-term sales revenues	4,440
Increase in operating revenues	$83,768

Retail electric revenues increased $59 million. Approximately $28 million of the increased revenues was due to the November 1994 base rate increase and approximately $11 million was due to the increase in retail kWh sales. Fuel and purchased power revenues increased $11 million as a result of the timing effect of fuel and purchased power cost recovery. However, these higher revenues are offset by higher fuel and purchased power expenses and have no net effect on earnings. Performance revenues, which vary annually based on the operating performance of Pilgrim Station, increased $9 million primarily due to a higher performance rate effective in 1995 and a 17% increase in generation.

A new annual conservation charge for recovery of demand side management program costs was implemented in February 1995. Under this charge all 1995 program costs were recovered in 1995. This resulted in higher DSM revenues and expenses than in prior years when certain program costs were capitalized for recovery over six years.

The net increase in wholesale and other revenues is primarily due to a $10 million decrease in revenue reserve provisions, which are primarily related to wholesale customer contract issues.

The increase in short-term sales revenues is due to higher short-term sales resulting from higher generating availability in 1995. Revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and therefore have no net effect on earnings.

Operating expenses

Total fuel and purchased power expenses increased $22 million primarily due to the timing effect of fuel and purchased power cost collection. Excluding the timing effect, fuel expense increased 5% due to an 8% increase in fossil station generation while purchased power expense was unchanged. Fuel and purchased power expenses are substantially all recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 0.9% over 1994. Employee benefit expenses increased primarily due to higher postretirement benefit expenses recorded in accordance with the 1992 settlement agreement. We also incurred higher administrative costs in positioning the company for changes in the industry, which were offset by lower operating costs in the electric delivery business. Electric generation costs increased only 1% in 1995, primarily due to a refueling and maintenance outage at Pilgrim Station.

The $34 million one-time restructuring charge was incurred over the third and fourth quarters of 1995 as a result of our corporate reorganization announced in July 1995. As part of the reorganization 330 employees elected to retire under enhanced retirement programs and 149 employees whose positions were eliminated became eligible for benefits under a special severance program. See Note F to the Consolidated Financial Statements for additional information. We expect to achieve ongoing savings as a result of the restructuring, with a payback period of approximately one year.

Depreciation and amortization expense increased due to a higher average depreciable plant balance.

In 1994 we fully expensed the remaining deferred costs of the cancelled Pilgrim 2 nuclear unit.

In the third quarter of 1995 we changed the amortization period of deferred nuclear outage costs to two years from five years as discussed in Note B to the Consolidated Financial Statements. The remaining $9 million of deferred costs allocable to retail customers for refueling outages performed in 1991 and 1993 was written off. Approximately $15 million of deferred costs from the 1995 refueling outage is being amortized over two years.

The increase in demand side management programs expense is related to the increase in DSM revenues. Beginning with the annual conservation charge implemented in February 1995, DSM costs are recovered and expensed primarily in the year incurred. The 1995 expense includes $31 million of 1995 program costs and $14 million of amortization of costs capitalized in 1992 through 1994.

Property and other taxes increased primarily due to higher Boston property taxes resulting from capital additions.

Our effective annual income tax rate for 1995 was 37.1% vs. 31.4% for 1994. The higher rate is the result of a $10 million adjustment to deferred income taxes made in 1994 in accordance with the 1992 settlement agreement.

Other income

The net decrease in other income is primarily due to a $5.7 million gain recognized in 1994 from a court ruling on a 1989 eminent domain taking of certain of our property.

Interest charges

Interest charges on long-term debt increased due to a $125 million debentures issuance in May 1995, partially offset by interest savings from first mortgage bond and debenture redemptions in 1994. Other interest charges increased slightly 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, decreased due to a lower construction work in progress balance and shorter construction periods, partially offset by a higher AFUDC rate related to the higher short-term interest rates.

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 $29 million annual 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 4.2% over 1993 as follows:

(in thousands)

Retail electric revenues	$62,945
Demand side management revenues	5,056
Wholesale and other revenues	(6,644)
Short-term sales revenues	1,219
Increase in operating revenues	$62,576

Retail electric revenues increased $63 million. The November 1993 and 1994 base rate increases resulted in $29 million of the increased revenues, and approximately $6 million was due to the 2% increase in retail kWh sales. Fuel and purchased power revenues increased $28 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.

Wholesale and other revenues decreased primarily due to an $8.5 million increase in revenue reserve provisions in 1994 related to certain wholesale customer 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 pur-

chased power cost collection also contributed to the decrease in fuel and purchased power expenses.

Other operations and maintenance expense increased 7.4% 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 recorded 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 in 1994 and 1993 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 from the statutory rate by adjustments to deferred income taxes of $10 million in 1994 and $20 million in 1993 made in accordance with the 1992 settlement agreement.

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 certain of our property.

Interest charges

Total interest charges 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. AFUDC increased as a result of a higher AFUDC rate related to the higher short-term interest rates.

Electric Sales and Revenues

Electric sales

Retail kWh sales increased 1.2% in 1995 primarily due to the positive effects of a stronger economy on commercial customers. This sector represents approximately 50% of our electric operating revenues.

Demand side management conservation programs are designed to assist customers in reducing electricity use and, therefore, result in lower growth in electricity sales. We receive approval from our state regulators for DSM spending levels and recovery amounts through an annual conservation charge. 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. In 1995 a new annual conservation charge was implemented under which all 1995 program costs were recovered in 1995. 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 are recovering over six years.

Electric revenues

As discussed in the Rate Regulation section, our 1992 settlement agreement provided us with two annual retail base rate increases of $29 million effective in 1993 and 1994 and an eight-year annual performance adjustment charge. We did not make a base rate filing upon the expiration of the settlement agreement in 1995, therefore base rates currently remain in effect at their 1995 levels. Due to our continued commitment to controlling costs and increasing operating efficiencies, maintaining these rate levels in our current regulatory environment is not expected to significantly affect our financial condition or results of operations.

The annual performance adjustment charge provides us with opportunities to improve our financial results. The most significant potential impact of this performance incentive is based on Pilgrim Station's annual capacity factor. An annual capacity factor between 60% and 68% would provide us with approximately $51 million of revenues in the performance year ended October 1996. For each percentage point increase in capacity factor above 68%, annual revenues will increase by approximately $750,000. For each percentage point decrease in capacity factor below 60% (to a minimum of 35%), annual revenues will decrease by approximately $840,000. Pilgrim's capacity factor for the performance year ending October 1996 is currently expected to be approximately 91%, an increase from the 67% capacity factor achieved in the performance year ended October 1995. There are no major outages scheduled for the current performance year. Pilgrim was out of service in November 1994 and for a 73-day refueling and maintenance outage in 1995. We earned approximately $49 million in revenues related to Pilgrim's capacity factor in the performance year ended October 31, 1995.

Pilgrim Station was shut down for three months in 1994 due to a non-nuclear problem with its electrical generator. Regularly scheduled maintenance work was also performed during the shutdown. The power needs usually met by the station were met by other generating plants or purchased from other suppliers as necessary. We do not believe that the generator damage resulted from actions within our control. Our recovery of the incremental purchased power costs during the outage through fuel and purchased power revenues, however, is subject to review by the DPU under a generating unit performance program.

Liquidity

We meet our capital expenditure cash requirements primarily with internally generated funds. These funds provided for 95%, 98% and 77% of our plant and nuclear fuel expenditures in 1995, 1994 and 1993, respectively. Our current estimate of plant expenditures for 1996 is $160 million. These expenditures will be used primarily to maintain and improve existing transmission and distribution facilities. We expect plant expenditures to remain level or decline slightly from the 1996 amount in the four years thereafter. In addition to capital expenditures we have long-term debt and preferred stock payment requirements of $103.6 million per year in 1996 through 1998, $3.6 million in 1999 and $168.6 million in 2000.

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, the Federal Energy Regulatory Commission (FERC), 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, 1995, we had $126 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. In 1994 the DPU approved our financing plan to issue up to $500 million of securities through 1996 using the proceeds to refinance short and long-term securities and for capital expenditures. Refer to Notes J and K to the Consolidated Financial Statements for specific information relating to our recent financing activities.

Outlook for the Future

Competition

Competitive pressures on the electric utility industry have increased due to a variety of factors, including legislative and regulatory proceedings at both federal and state levels and changes in customer expectations. The trend is toward promotion of increased competition through modified regulation of the industry.

To date the effects of competition have been most prominent in the wholesale electric market. In response to increased competition from other electric utilities and nonutility generators to sell electricity for resale, we secured long-term power supply agreements with our six wholesale customers that set rates through 2002 and beyond. In 1995, our largest retail customer, the Massachusetts Port Authority (Massport), issued a request for proposals for a wholesale supplier of electricity. We successfully retained Massport as a customer through a ten-year wholesale power supply agreement effective November 1995. We are awaiting approval of this agreement from the FERC.

In March 1995 the FERC issued a Notice of Proposed Rulemaking (NOPR) addressing open transmission access and recovery of previously incurred costs. If approved, the NOPR would require all utilities with transmission systems to file open access tariffs at the FERC, to provide service under those tariffs to transmission customers comparable to service provided to their electric energy customers and to take service under the tariffs for wholesale purchases and sales. The NOPR also supports the full recovery of legitimate and verifiable costs previously incurred under federal and state regulation. The provisions in the NOPR provide a framework for significant changes in the electric utility industry.

We have also been experiencing increased competition in the retail electric market. Competition currently exists with alternative fuel suppliers as customers are able to substitute natural gas, steam or oil for electricity for heating or cooling purposes. In addition, industrial and large commercial customers may pursue options to generate their own electric power or factor the cost of electricity into their decisions to relocate to new service territories. Electric utilities are thus under increasing pressure from these customers to discount rates.

In August 1995 the DPU issued an order on restructuring of the electric utility industry. The order provides for Massachusetts-based electric utilities to restructure their operations to encourage more competition for customers. It also includes the following principles for a restructured electric industry:

- provide the broadest possible customer choice
- provide all customers with an opportunity to share in the benefits of increased competition
- ensure full and fair competition in generation markets
- functionally separate generation, transmission and distribution services
- provide universal service
- support and further the goals of environmental regulation
- rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist

The DPU order also set the following principles to guide the transition from a regulated to a competitive industry structure:

- honor existing commitments
- unbundle rates for generation, transmission and distribution
- reduce rates in the near term

- maintain demand side management programs
- ensure an orderly and quick transition that minimizes customer confusion

The order provides a reasonable opportunity for the recovery of net, nonmitigatable potentially strandable costs (strandable costs), over a period of up to ten years. These costs include investments in plant that might not be recoverable in a competitive market, liabilities for future decommissioning of nuclear plants, the amounts by which certain purchase power contracts exceed the competitive price for generation, and prudently incurred regulatory assets. We are looking at possibilities for mitigating our potentially strandable costs, including potential revisions to depreciation and amortization periods.

The order establishes only general principles for the transition to a competitive market and does not establish a particular model for the new industry structure. Each of the Massachusetts-based electric utilities is required to develop a plan for moving toward competition consistent with the DPU's order and encouraged to negotiate with all interested parties while doing so. We were one of three companies required to file a restructuring plan in February 1996. Our plan is consistent with the general principles outlined in the order, including unbundled rates for generation, transmission and distribution. It provides for and is based upon full recovery of strandable costs through a nonbypassable access charge. This charge is to be paid by customers as a condition of receiving service over our distribution system, which remains a monopoly function. We expect to enter into negotiations with intervening parties that will result in new rates and performance incentives to be implemented in the new industry structure.

In addition to our involvement in the DPU's restructuring proceedings, we are actively responding to the current and anticipated changes in the industry in several ways. In 1995 we reorganized the company into separate business units in order to strengthen our competitiveness. These business units, Customer, Generating-Fossil, Generating-Nuclear and Corporate Services, were designed to sharpen management focus along our significant lines of operation while maintaining company-wide strategic goals. As a result of enhanced retirement programs and a special severance program offered during this corporate restructuring, we reduced our workforce by 12%. We expect to achieve ongoing savings as a result of the restructuring, with a payback period of approximately one year. We also continued to develop customer alliances and provided economic development rates to some customers. In addition, we currently have a special lower rate available for a small number of large manufacturing customers on a limited basis and we recently implemented a one-year pilot program that uses a competitive market index to set electric rates for a limited number of customers. These actions all signify our commitment to be a competitively priced, reliable provider of energy. We do not expect the economic development rates, the lower manufacturing customer rates or the pilot program to have a significant impact on our financial condition or results of operations.

In the rate-regulated environment based on cost recovery that we have traditionally operated in, we are subject to certain accounting standards that are not applicable to other businesses and industries. The standards allow us to record certain costs as regulatory assets instead of as expenses when incurred when we expect to receive future rate recovery of the costs. We believe that we currently meet the criteria of these standards. In addition to the specifically identified regulatory assets on our consolidated balance sheets, there may be differences in the carrying value of our net utility plant compared to what the amount would have been if we were not subject to rate regulation. These potential differences would be due to differing plant depreciable lives for regulatory and non-regulatory accounting standards. We have not yet fully determined to what extent such differences may exist. The effects of competition and modified regulation could, in the near term, cause us to no longer meet the criteria for application of the regulatory accounting standards for some of our operations. Should this occur we would have to take a noncash write-off of our affected regulatory assets and adjust our affected plant balances if necessary by recording an addition to depreciation expense at that time. However, the DPU order on industry restructuring provides a reasonable opportunity for recovery of these previously incurred costs, which are also provided for in our related plan. We expect to recover all strandable costs through our distribution system, which we expect will remain rate-regulated, and therefore will continue to meet the criteria of these accounting standards. If it does not continue to be likely that we will recover all our regulatory assets and generating plant costs as our restructuring plan is ultimately finalized, we would have to write off such portions that are no longer probable of recovery in accordance with Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of. See Note M to the Consolidated Financial Statements for information on this new accounting standard. The nonrecovery of specifically identified and other embedded regulatory assets or plant costs could have a material impact on our results of operations and financial condition.

Resource regulation

In this period of transition in the electric utility industry we remain subject to current regulatory requirements. The DPU requires utilities to purchase power from qualifying nonutility generators at prices set through a bidding process. In a continuation of a dispute which originated in 1991, the DPU is currently investigating whether we should again be ordered to negotiate a contract to purchase power from an independent power producer, JMC Altresco, Inc. We have consistently opposed this order since we do not believe we need any new

power for several years and the proposed contract would impose excessive costs on our customers. In 1995 we filed a motion to dismiss the matter, which is pending. We also filed testimony comparing the cost of Altresco to projected market costs and hearings are currently ongoing. In a separate but related matter, we appealed the Massachusetts Energy Facilities Siting Board's (EFSB) approval of construction of Altresco's proposed generating station based partly on the EFSB's failure to consider market information and forecasts.

We also currently remain subject to the DPU's 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. As a result of our 1994 IRM filing, the DPU found that we did not have a need for additional generating capacity through 2001 and therefore were not required to issue a competitive request for proposals for new generating capacity. Required updates to our IRM filing have been postponed due to the current industry restructuring proceedings ongoing at the DPU.

Nonutility business

We have an unregulated subsidiary, Boston Energy Technology Group (BETG), in which we have authority from the DPU to invest up to $45 million. This wholly owned subsidiary engages primarily in energy conservation services and the production of water treatment systems. In 1996 BETG entered into a joint venture to build a series of ice-based cooling systems as an alternative to costly chemical systems. BETG's investment in this joint venture, Northwind Boston, is 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 approximately 40 properties where oil or hazardous materials were previously spilled or released. 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 approximately 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, 1995, 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 that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

Uncertainties continue to exist with respect to the disposal of both spent nuclear fuel and low-level radioactive waste (LLW) resulting from the operation of Pilgrim Station. 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. In 1995 we regained access to the LLW disposal facility located in Barnwell, South Carolina. Refer to Note E to the Consolidated Financial Statements for further discussion regarding spent nuclear fuel and LLW disposal.

As part of a 1991 DEP consent order, we are currently required to fuel New Boston Station exclusively by natural gas, except in certain emergency circumstances. The station has the ability to burn natural gas, oil or both. We have arrangements for a firm supply of natural gas to run the station at a minimum level and are developing a least-cost plan for operating beyond this minimum level which principally utilizes interruptible gas supplies or short-term capacity purchases.

The 1990 Clean Air Act Amendments 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 allowances 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 low nitrogen oxides burners at New Boston, have allowed the units to meet the provisions of the 1995 standards. Depending upon the outcome of certain DEP air quality modeling studies current-

ly in progress, additional emission reductions may also be required by 1999 or years thereafter. The extent of any additional emission restrictions and the cost of any further modifications is uncertain at this time.

Public concern continues 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. We have also been named as a party in a lawsuit by Subaru of New England, Inc. and Subaru Distributors Corporation. The plaintiffs are claiming certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from New Boston Station. We believe that we have a strong defense in this case. We are also involved in certain other legal matters. We are unable to fully determine a range of reasonably possible litigation costs in excess of amounts previously accrued, although based on the information currently available, we do not expect that any such additional costs will have a material impact on our financial condition. However, additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

New accounting pronouncement

Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of, is effective in 1996. This statement establishes accounting standards for recognizing and measuring asset impairment losses. Refer to Note M to the Consolidated Financial Statements for more information regarding this statement and its potential effects.

Safe harbor cautionary statement

We occasionally make forward-looking statements such as forecasts and projections of expected future performance or statements of our plans and objectives. These forward-looking statements may be contained in filings with the Securities and Exchange Commission, press releases and oral statements. Actual results could potentially differ materially from these statements. Therefore, no assurances can be given that the outcomes stated in such forward-looking statements and estimates will be achieved.

The above sections include certain forward-looking statements about the effects of the industry restructuring process and our related plan, operating results, Pilgrim Station's performance and environmental and legal issues.

The effects of the industry restructuring process currently underway at the DPU and our related plan could differ from our expectations. This could occur as regulatory decisions and negotiated settlements between utilities and intervenors are finalized during the restructuring process. In addition, the development of a competitive electric generation market and the impacts of actual electric supply and demand in New England may affect the ultimate results of the industry restructuring and our plan.

The impacts of our continued cost control procedures on our operating results could differ from our expectations. The effects of changes in economic conditions, tax rates, interest rates, technology and the prices and availability of operating supplies could materially affect our projected operating results.

Pilgrim Station's performance could differ from our expectations. The station's capacity factor could be impacted by changes in regulations or by unplanned outages resulting from certain operating conditions.

The impacts of various environmental and legal issues could differ from our expectations. New regulations or changes to existing regulations could impose additional operating requirements or liabilities. The effects of changes in specific hazardous waste site conditions and cleanup technology could affect our estimated cleanup liabilities. The impacts of changes in available information and circumstances regarding legal issues could affect our estimated litigation costs.

Consolidated Statements of Income

(in thousands, except earnings per share)	1995	1994	years ended December 31, 1993
Operating revenues	**$1,628,503**	$1,544,735	$1,482,159
Operating expenses:			
Fuel	**170,337**	156,951	170,799
Purchased power	**365,469**	356,874	370,049
Other operations and maintenance	**439,263**	435,824	405,609
Restructuring costs	**34,000**	0	0
Depreciation and amortization	**153,339**	148,845	137,710
Amortization of deferred cost of cancelled nuclear unit	**0**	19,791	0
Amortization of deferred nuclear outage costs	**18,933**	7,721	6,546
Demand side management programs	**45,125**	35,438	37,504
Taxes - property and other	**106,361**	100,015	93,102
Income taxes	**68,276**	54,798	35,143
Total operating expenses	**1,401,103**	1,316,257	1,256,462
Operating income	**227,400**	228,478	225,697
Other income (expense), net	**(575)**	3,979	211
Operating and other income	**226,825**	232,457	225,908
Interest charges:			
Long-term debt	**106,640**	102,570	104,375
Other	**12,642**	12,343	9,778
Allowance for borrowed funds used during construction	**(4,767)**	(7,478)	(6,463)
Total interest charges	**114,515**	107,435	107,690
Net income	**112,310**	125,022	118,218
Preferred dividends provided	**15,571**	15,765	15,705
Balance available for common stock	**$ 96,739**	$ 109,257	$ 102,513
Weighted average common shares outstanding	**46,592**	45,338	44,959
Earnings per share of common stock	**$ 2.08**	$ 2.41	$ 2.28

Consolidated Statements of Retained Earnings

(in thousands)	1995	1994	years ended December 31, 1993
Balance at beginning of year	**$ 247,004**	$ 218,292	$ 192,948
Net income	**112,310**	125,022	118,218
Subtotal	**359,314**	343,314	311,166
Cash dividends declared:			
Preferred stock	**15,571**	15,765	15,705
Common stock	**86,399**	80,545	77,169
Subtotal	**101,970**	96,310	92,874
Balance at end of year	**$ 257,344**	$ 247,004	$ 218,292

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

Consolidated Balance Sheets

(in thousands)		1995		December 31, 1994
Assets				
Utility plant in service, at original cost	**$4,315,422**		$4,074,810	
Less: accumulated depreciation	**1,439,996**	**$2,875,426**	1,344,452	$2,730,358
Nuclear fuel	**302,594**		291,836	
Less: accumulated amortization	**251,951**	**50,643**	236,239	55,597
Construction work in progress		**29,573**		144,048
Net utility plant		**2,955,642**		2,930,003
Investments in electric companies, at equity		**23,620**		24,678
Nuclear decommissioning trust		**102,894**		82,831
Current assets:				
Cash and cash equivalents	**5,841**		6,822	
Accounts receivable	**219,114**		189,361	
Accrued unbilled revenues	**37,113**		32,240	
Fuel, materials and supplies, at average cost	**59,631**		71,560	
Prepaid expenses and other	**23,607**	**345,306**	26,693	326,676
Deferred debits:				
Regulatory assets	**156,774**		198,148	
Intangible asset - pension	**27,386**		22,849	
Other	**32,227**	**216,387**	31,391	252,388
Total assets		**$3,643,849**		$3,616,576
Capitalization and Liabilities				
Common stock equity		**$ 989,438**		$ 915,747
Cumulative preferred stock:				
Nonmandatory redeemable series		**123,000**		123,000
Mandatory redeemable series		**92,000**		94,000
Long-term debt		**1,160,223**		1,136,617
Current liabilities:				
Long-term debt/preferred stock due within one year	**$ 102,667**		$ 102,250	
Notes payable	**126,441**		214,786	
Accounts payable	**133,474**		130,496	
Accrued interest	**25,113**		24,464	
Dividends payable	**25,351**		23,533	
Pension benefits	**32,602**		31,908	
Other	**105,442**	**551,090**	85,204	612,641
Deferred credits:				
Power contracts	**21,396**		40,277	
Accumulated deferred income taxes	**497,282**		515,454	
Accumulated deferred investment tax credits	**62,970**		67,048	
Nuclear decommissioning reserve	**113,288**		92,404	
Other	**33,162**	**728,098**	19,388	734,571
Commitments and contingencies		**–**		–
Total capitalization and liabilities		**$3,643,849**		$3,616,576

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

Consolidated Statements of Cash Flows

(in thousands)	1995	years ended December 31, 1994	1993
Operating activities:			
Net income	**$ 112,310**	$125,022	$118,218
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	**148,630**	142,932	130,074
Amortization of nuclear fuel	**19,029**	18,810	21,816
Amortization of deferred cost of cancelled nuclear unit, net	**0**	19,067	0
Amortization of deferred nuclear outage costs	**18,933**	7,721	6,546
Other amortization	**15,702**	14,692	10,158
Deferred income taxes	**(21,115)**	(4,184)	10,303
Investment tax credits	**(4,078)**	(4,092)	(4,073)
Allowance for borrowed funds used during construction	**(4,767)**	(7,478)	(6,463)
Net changes in:			
Accounts receivable and accrued unbilled revenues	**(34,626)**	(20,701)	13,206
Fuel, materials and supplies	**7,202**	3,093	9,722
Accounts payable	**2,978**	23,196	(18,916)
Other current assets and liabilities	**26,485**	35,217	25,660
Other, net	**23,975**	14,847	(20,437)
Net cash provided by operating activities	**310,658**	368,142	295,814
Investing activities:			
Plant expenditures (excluding AFUDC)	**(180,822)**	(198,771)	(246,774)
Nuclear fuel expenditures	**(13,621)**	(21,934)	(6,491)
Capitalized demand side management expenditures	**0**	(37,007)	(37,156)
Sale of plant assets, net	**3,018**	15,972	0
Nuclear decommissioning trust investments	**(20,063)**	(16,771)	(15,189)
Electric company investments	**1,058**	(386)	1,106
Net cash used by investing activities	**(210,430)**	(258,897)	(304,504)
Financing activities:			
Issuances:			
Common stock	**64,888**	10,634	10,855
Preferred stock	**0**	0	40,000
Long-term debt	**125,000**	15,000	815,000
Redemptions:			
Preferred stock	**(2,000)**	(2,000)	(40,000)
Long-term debt	**(100,600)**	(50,000)	(648,625)
Net change in notes payable	**(88,345)**	10,635	(71,349)
Dividends paid	**(100,152)**	(95,460)	(92,370)
Net cash provided (used) by financing activities	**(101,209)**	(111,191)	13,511
Net increase (decrease) in cash and cash equivalents	**(981)**	(1,946)	4,821
Cash and cash equivalents at the beginning of the year	**6,822**	8,768	3,947
Cash and cash equivalents at the end of the year	**$ 5,841**	$ 6,822	$ 8,768

Cash paid during the year for:			
Interest, net of amounts capitalized	**$ 113,945**	$108,462	$103,720
Income taxes	**$ 96,180**	$ 46,074	$ 30,305

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

Notes to Consolidated Financial Statements

Note A. Nature of Operations

We are an investor-owned regulated public utility operating in the energy and energy services business. This includes the generation, purchase, transmission, distribution and sale of electric energy and the development and implementation of electric demand side management programs. A portion of our generation is produced by a nuclear unit, Pilgrim Station. We supply electricity at retail to an area of 590 square miles, including the City of Boston and 39 surrounding cities and towns. We also supply electricity at wholesale for resale to other utilities and municipal electric departments. Electric operating revenues were 89% retail and 11% wholesale in 1995.

Note B. 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. Certain prior period amounts on the financial statements were reclassified to conform with the current presentation.

We follow accounting policies prescribed by our federal and state regulators, the Federal Energy Regulatory Commission (FERC) and the Massachusetts Department of Public Utilities (DPU). We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The financial statements conform with generally accepted accounting principles (GAAP). As a rate-regulated company we are subject to Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71), under GAAP. The application of SFAS 71 results in differences in the timing of recognition of certain expenses from that of other businesses and industries. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

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 1995, 1994 and 1993 at composite rates of 3.10%, 3.11% and 3.09% per year, respectively, based on estimated useful lives of the various classes of property. The cost of decommissioning Pilgrim Station is excluded from these 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 defer the incremental costs associated with nuclear refueling outages and amortize them over future periods. In 1995 we changed the amortization period to two years from five years. The two-year amortization period is consistent with the two-year cycle between nuclear refueling outages at Pilgrim Station. The change from the prior five-year amortization period approved in the 1992 settlement agreement was made following the DPU's August 1995 order on electric industry restructuring, which is dis-

cussed further in the Outlook for the Future section of Management's Discussion and Analysis. This order requires utilities to mitigate potentially strandable costs by available and reasonable means. The prior regulatory treatment of recovery over a five year period resulted in a significant lag between the expenditure and recovery of outage costs. We decided not to request recovery of the buildup of costs resulting from this regulatory lag. Accordingly, the remaining $9 million of deferred costs allocable to retail customers for refueling outages performed in 1991 and 1993 was written off. Approximately $15 million of deferred costs from the 1995 refueling outage is being amortized over two years.

6. Amortization of Discounts and Redemption Premiums on Debt

We expense discounts, 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 1995, 1994 and 1993 were 6.35%, 4.45% and 3.62%, 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 when purchased. Outstanding checks are included in cash and accounts payable until 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 are expected to be collected from customers through future charges in accordance with agreements with the DPU. These costs are to be expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. The majority of these costs is currently being recovered from customers over varying time periods. No return on investment was earned on the regulatory assets.

Regulatory assets consisted of the following:

	December 31,	
	1995	1994
Redemption premiums	**$ 44,709**	$ 52,859
Income taxes, net	**46,121**	44,745
Power contracts	**21,396**	40,277
Pension and postretirement costs	**13,811**	22,761
Nuclear outage costs	**13,471**	17,804
Other	**17,266**	19,702
	$ 156,774	$198,148

Note C. Rate Regulation

In 1992 the DPU approved a three-year settlement agreement relating to our rate case proceedings. The agreement 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 through 1995.

In February 1996 we filed an industry restructuring plan with the DPU in response to its August 1995 order on restructuring the electric utility industry. This plan is expected to lead to negotiations with intervening parties that will result in new rates and performance incentives to be implemented in a new industry structure with a competitive generation market and incentive-regulated transmission and distribution systems. Refer to Management's Discussion and Analysis for further information regarding the restructuring of the electric utility industry in Massachusetts and our proposed plan. State regulatory proceedings do not affect our contract or wholesale power rates, which are regulated by the FERC.

Note D. Income Taxes

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109), which 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 $46.1 million and $44.7 million and corresponding net increases in accumulated deferred income taxes as of December 31, 1995, and December 31, 1994, 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:

(in thousands)		December 31,
	1995	1994
Deferred tax liabilities:		
Plant-related	**$ 521,280**	$511,572
Other	**95,148**	105,786
	616,428	617,358
Deferred tax assets:		
Plant-related	**12,590**	13,216
Investment tax credits	**40,632**	43,273
Alternative minimum tax	**0**	1,332
Other	**65,924**	44,083
	119,146	101,904
Net accumulated deferred income taxes	**$ 497,282**	$515,454

No valuation allowances for deferred tax assets are deemed necessary.

Components of income tax expense were as follows:

(in thousands)		years ended December 31,	
	1995	1994	1993
Current income tax expense	**$93,469**	$ 63,358	$ 28,913
Deferred tax expense	**(21,115)**	(4,468)	10,303
Investment tax credits	**(4,078)**	(4,092)	(4,073)
Income taxes charged to operations	**68,276**	54,798	35,143
Taxes on other income:			
Current	**(1,729)**	2,550	1,205
Deferred	**0**	284	0
	(1,729)	2,834	1,205
Total income tax expense	**$66,547**	$ 57,632	$ 36,348

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:

	1995	1994	1993
Statutory tax rate	**35.0%**	35.0%	35.0%
State income tax, net of federal income tax benefit	**4.3**	4.3	4.2
Investment tax credits	**(2.3)**	(2.3)	(2.6)
Municipal property tax adjustment	**–**	–	(0.6)
Reversal of deferred taxes - settlement agreement	**–**	(5.5)	(13.0)
Other	**0.1**	(0.1)	0.4
Effective tax rate	**37.1%**	31.4%	23.4%

Note E. 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 currently expensing an estimate of the decommissioning costs over Pilgrim's expected service life. The 1995 expense of approximately $14 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 that 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 which 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 in order to evaluate the potential impact of long-term spent fuel storage options resulting from delays in the United States Department of Energy (DOE) spent fuel removal program. (See part 2 below for a discussion of spent fuel removal.) The partial update indicates an estimated decommissioning cost of $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 February 1996 the Financial Accounting Standards Board (FASB) issued proposed new rules for accounting for liabilities related to closure and removal of long-lived assets, which includes decommissioning. If these draft rules are adopted we would be required to retroactively recognize the entire estimated liability for decommissioning costs on the balance sheet, offset by an addition to nuclear plant. The plant addition would be depreciated over Pilgrim's expected service life. The liability would be measured based on the present value of estimated future cash flows. The cumulative effect of adoption of these proposed rules could result in a regulatory asset to be recovered from customers to the extent that the present value difference in the liability between when the liability was incurred and when the rules are adopted exceeds the depreciation expense previously recognized for decommissioning. If it is not probable that we could recover these costs from customers, we would have to charge the cumulative effect of the difference to income instead of recording a regulatory asset. In addition, trust fund earnings would be reported on the income statement.

2. Spent Nuclear Fuel

The spent fuel storage facility at Pilgrim Station provides storage capacity through approximately 2003. We have a license amendment from the Nuclear Regulatory Commission to modify the facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012; however, any further modifications are subject to review by the DPU. 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 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 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

We regained access to low-level radioactive waste (LLW) disposal facilities located in Barnwell, South Carolina, in 1995. This site is currently the only disposal facility available to us. 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. 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 F. Corporate Restructuring

In 1995 we streamlined the corporate organization and reorganized the company into separate business units in order to strengthen our competitiveness in the changing electric energy market. In conjunction with this reorganization we offered enhanced retirement programs and implemented a special severance program to reduce employee staffing levels. Under the enhanced retirement programs 330 employees elected to retire, and 149 employees whose positions were eliminated became eligible for benefits under the special severance program. These programs resulted in a $34 million pre-tax charge ($20.7 million net of tax) over the third and fourth quarters of 1995. The charge consisted of $24 million for the retirement programs and $10 million for the severance program.

The enhanced retirement programs were offered to all employees at least 55 years old, with different years of service requirements for management and union employees. The programs provided for supplemental salary payments and waivers of the early retirement pension reduction and the medical and life insurance benefits years of service requirement. The special severance program was provided for all employees whose positions were eliminated in the reorganization, who were all management and administrative support personnel. Severance benefits provided were salary payments, medical insurance and outplacement services. The retirement programs' pension and medical and life insurance benefits, totalling $16 million, will be paid from pension and employee benefit trusts. The liabilities to the trusts are included on the consolidated balance sheet at December 31, 1995, in pension benefits and other current liabilities. All other benefits are being paid from general corporate funds. As of December 31, 1995, $10 million had been paid and $8 million remained in other current liabilities.

Note G. Pensions and Other Postretirement 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 highest eligible average compensation during the last ten years of credited 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. The retirement plan assets consist of equities, bonds, money market funds, insurance contracts and real estate funds.

We also have a supplemental pension plan for certain management employees. Benefits under this plan are based on final compensation upon retirement. The plan is not funded. The plan's cost and benefit obligation amounts are included in the following pension information for 1995. Amounts related to the plan prior to 1995 were not material to our total pension costs and obligations.

Net pension cost consisted of the following components:

		years ended December 31,	
(in thousands)	**1995**	1994	1993
Current service cost - benefits earned	**$11,339**	$ 15,057	$ 11,734
Interest cost on projected benefit obligation	**31,789**	33,961	33,181
Actual net loss/(return) on plan assets	**(72,192)**	214	(44,470)
Net amortization and deferral	**49,557**	(32,169)	8,528
Net pension cost (a)	**$20,493**	$ 17,063	$ 8,973

(a) In accordance with our 1992 settlement agreement we deferred the difference in the net pension cost of the retirement plan and its annual funding amount. Net deferred costs amounted to ($1.2) million and $6.5 million at December 31, 1995 and 1994, respectively. Total net pension costs recorded as expense in 1995, 1994 and 1993 were $28 million, $25 million and $5 million, respectively.

We used the following assumptions for calculating pension cost:

	1995	1994	1993
Discount rate	**8.25%**	7.00%	8.25%
Expected long-term rate of return on assets	**10.00%**	10.00%	10.00%
Compensation increase rate	**3.90%**	4.50%	4.50%

The pension plans' funded status was as follows:

(in thousands)	December 31, 1995	1994
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $386,020 and $305,632 (b)	**$ 401,329**	$321,072
Plan assets at fair value	**$ 358,572**	$289,164
Projected obligation for service rendered to date	**(487,702)**	(387,910)
Projected benefit obligation in excess of plan assets	**(129,130)**	(98,746)
Unrecognized prior service cost	**22,506**	13,328
Unrecognized net loss	**83,187**	67,361
Unrecognized net obligation	**8,064**	8,998
Minimum liability adjustment (c)	**(27,386)**	(22,849)
Net pension liability (d)	**$ (42,759)**	$(31,908)

(b) The accumulated benefit obligation at December 31, 1995, includes $13.5 million related to the enhanced retirement programs offered in 1995 as discussed in Note F.

(c) 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 additional minimum liabilities and corresponding intangible assets of $27 million and $23 million on our consolidated balance sheets at December 31, 1995 and 1994, respectively.

(d) Net pension liability included on the consolidated balance sheets in current liabilities is $33 million and $32 million, and in deferred credits is $10 million and $0 at December 31, 1995 and 1994, respectively.

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

	1995	1994
Discount rate	**7.25%**	8.25%
Compensation increase rate	**3.90%**	3.90%

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 $9 million in 1995, $8 million in 1994 and $7 million in 1993.

2. Other Postretirement Benefits

In addition to pension benefits, we also provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. These postretirement benefits other than pensions (PBOPs) are accounted for in accordance with Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). Our 1992 settlement agreement provides us with a five-year expense phase-in of the PBOP costs incurred under SFAS 106 and allows us to defer any 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 benefits costs to external trusts. Accordingly, we recorded expenses of $23 million in 1995, $17 million in 1994 and $15 million in 1993, reflecting the amount of current cost recovery from customers. Net deferred costs amounted to $15 million and $16 million at December 31, 1995 and 1994, respectively.

Net postretirement benefits cost consisted of the following components:

(in thousands)	1995	years ended December 31, 1994	1993
Current service cost - benefits earned	**$ 3,408**	$ 4,978	$ 4,351
Interest cost on accumulated benefit obligation	**13,521**	13,632	14,286
Actual return on plan assets	**(7,151)**	(187)	0
Amortization of transition obligation	**9,151**	9,151	9,151
Net amortization and deferral	**3,017**	(2,581)	0
Net postretirement benefits cost	**$21,946**	$ 24,993	$ 27,788

We used the following assumptions for calculating postretirement benefits cost:

	1995	1994	1993
Discount rate	**8.25%**	7.00%	8.00%
Expected long-term rate of return on assets	**9.00%**	9.00%	9.00%
Health care cost trend rate	**7.00%**	9.00%	12.50%

The health care cost trend rate is assumed to decrease by one percent in 1996 and 1997 and to remain at 5% in 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 8% and would increase the accumulated benefit obligation at December 31, 1995, by 7.5%.

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

(in thousands)		1995		December 31, 1994
Trust assets at fair value		**$ 51,064**		$ 33,300
Accumulated obligation for service rendered to date from:				
Retirees	**$ (110,877)**		$ (93,960)	
Active employees eligible to retire	**(31,980)**		(31,159)	
Active employees not eligible to retire	**(53,514)**	**(196,371)**	(51,545)	(176,664)
Accumulated benefit obligation in excess of trust assets		**(145,307)**		(143,364)
Unrecognized prior service cost		**(17,889)**		(19,502)
Unrecognized net (gain)/loss		**5,612**		(1,849)
Unrecognized transition obligation		**155,564**		164,715
Net postretirement benefits liability		**$ (2,020)**		$ 0

The net postretirement benefits liability at December 31, 1995, represents the additional PBOP obligation from the enhanced retirement programs offered in 1995 (see Note F). This additional amount was not funded as part of the 1995 PBOP cost.

The weighted average discount rates used to measure the accumulated benefit obligation were 7.25% in 1995 and 8.25% in 1994. The trust assets consist of equities, bonds and money market funds.

Note H. 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 I. Cancelled Nuclear Unit

In 1982 we began expensing the cost of our cancelled Pilgrim 2 nuclear unit over approximately eleven and one-half years in accordance with an order received from the DPU. 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 1992 settlement agreement.

Note J. Capital Stock

(dollars in thousands, except per share amounts)				1995	1994	December 31, 1993
Common stock equity:						
Common stock, par value $1 per share, 100,000,000 shares authorized; 48,003,178, 45,535,477 and 45,129,227 shares issued and outstanding:				**$ 48,003**	$ 45,535	$ 45,129
Premium on common stock				**683,686**	622,803	612,653
Retained earnings				**257,344**	247,004	218,292
Surplus invested in plant				**405**	405	405
Total common stock equity				**$ 989,438**	$915,747	$876,479

Cumulative preferred stock:

Par value $100 per share, 2,890,000 shares authorized; issued and outstanding:

Nonmandatory redeemable series:

Series	Current Shares Outstanding	Redemption Price/Share	1995	1994	1993
4.25%	180,000	$103.625	**$ 18,000**	$ 18,000	$ 18,000
4.78%	250,000	$102.800	**25,000**	25,000	25,000
7.75%	400,000	–	**40,000**	40,000	40,000
8.25%	400,000	–	**40,000**	40,000	40,000
Total nonmandatory redeemable series			**$ 123,000**	$123,000	$123,000

Mandatory redeemable series:

Series	Current Shares Outstanding	Redemption Price/Share	1995	1994	1993
7.27%	440,000	$103.390	**$ 44,000**	$ 46,000	$ 48,000
8.00%	500,000	–	**50,000**	50,000	50,000
Total mandatory redeemable series			**94,000**	96,000	98,000
Less: due within one year			**2,000**	2,000	2,000
Total mandatory redeemable series, net			**$ 92,000**	$ 94,000	$ 96,000

Dividends Declared per Share

	1995	1994	1993
Common stock	**$ 1.835**	$ 1.775	$ 1.715
Preferred stock:			
4.25% series	**$ 4.250**	$ 4.250	$ 4.253
4.78% series	**4.780**	4.780	4.785
7.27% series	**7.270**	7.270	7.270
7.75% series	**7.750**	7.750	5.707
8.00% series	**8.000**	8.000	8.000
8.25% series	**8.250**	8.250	8.250
8.88% series	**0**	0	2.220

1. Common Stock

Common stock issuances in 1993 through 1995 were as follows:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
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	406	406	10,150
Balance December 31, 1994	45,535	45,535	622,803
Dividend reinvestment plan (a)	468	468	11,404
New issuances (b)	2,000	2,000	49,479
Balance December 31, 1995	48,003	$48,003	$683,686

(a) At December 31, 1995, the remaining authorized common shares reserved for future issuance under the Dividend Reinvestment and Common Stock Purchase Plar were 1,941,219 shares.

(b) We used the net proceeds of the 1995 common stock issuances to reduce short-term debt.

2. Cumulative Nonmandatory Redeemable Preferred Stock

In 1993 we issued 400,000 shares of 7.75% cumulative nonmandatory 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 nonmandatory redeemable preferred stock.

3. Cumulative Mandatory Redeemable Preferred Stock

The 440,000 shares of 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $103.390. 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 noncumulative 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 the 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.

Note K. Indebtedness

(in thousands)	December 31, 1995	1994
Long-term debt:		
Debentures:		
8.875%, due December 1995	**$ 0**	$ 100,000
5.125%, due March 1996	**100,000**	100,000
5.700%, due March 1997	**100,000**	100,000
5.950%, due March 1998	**100,000**	100,000
6.800%, due February 2000	**65,000**	65,000
6.050%, due August 2000	**100,000**	100,000
6.800%, due March 2003	**150,000**	150,000
7.800%, due May 2010	**125,000**	0
9.875%, due June 2020	**100,000**	100,000
9.375%, due August 2021	**115,000**	115,000
8.250%, due September 2022	**60,000**	60,000
7.800%, due March 2023	**200,000**	200,000
Total debentures	**1,215,000**	1,190,000
Less: due within one year	**100,000**	100,000
Net long-term debentures	**1,115,000**	1,090,000

Note K. Indebtedness cont.

(in thousands)		December 31, 1995		1994
Sewage facility revenue bonds	$	**35,700**	$	36,300
Less: due within one year		**1,600**		600
Less: funds held by trustee		**3,877**		4,083
Net long-term sewage facility revenue bonds		**30,223**		31,617
Massachusetts Industrial Finance Agency bonds:				
5.750%, due February 2014		**15,000**		15,000
Total long-term debt		**$1,160,223**		$ 1,136,617
Short-term debt:				
Notes payable:				
Bank loans	$	**75,941**	$	80,786
Commercial paper		**50,500**		134,000
Total notes payable	$	**126,441**	$	214,786

1. Long-Term Debt

In 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.

In 1994 we redeemed at par the $25 million of variable rate Series S first mortgage bonds. 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.

In May 1995 we issued $125 million of 7.80% debentures due in 2010. We used the net proceeds from this issuance to reduce short-term debt.

The 9 7/8% debentures due 2020 are first redeemable in June 2000 at a redemption price of 104.483%, the 9 3/8% series due 2021 are first redeemable in August 2001 at 104.612%, the 8.25% series due 2022 are first redeemable in September 2002 at 103.780% and the 7.80% series due 2023 are first redeemable in March 2003 at 103.730%. No other series are redeemable prior to maturity. There is no sinking fund requirement for any series of our debentures.

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 through 2015. In May 1995 $0.6 million was redeemed as scheduled. 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 for extraordinary expenses, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $1 million.

The aggregate principal amounts of our long-term debt (including HEEC sinking fund requirements) due through 2000 are $101.6 million per year in 1996 through 1998, $1.6 million in 1999 and $166.6 million in 2000.

2. 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 stand-by 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:

(dollars in thousands)	1995	1994	1993
Maximum short-term borrowings	**$327,769**	$ 268,100	$ 320,000
Weighted average amount outstanding	**$165,720**	$ 214,640	$ 220,149
Weighted average interest rate, excluding commitment fees	**6.2%**	4.5%	3.4%

Note L. 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 $102.9 million approximates fair value based on quoted market prices of securities held.

Cash and cash equivalents:

The carrying amount of $5.8 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, 1995, are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 94,000	$ 98,005
Sewage facility revenue bonds	35,700	38,446
Unsecured debt	1,230,000	1,276,213

Note M. New Accounting Pronouncement

In 1995 the FASB issued Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of (SFAS 121), effective in 1996. This statement clarifies when and how to recognize asset impairments. In addition, SFAS 121 requires that all regulatory assets, which must have a high probability of recovery to be initially established, continue to meet that high probability standard or be written off. However, if written off, a regulatory asset can be restored if it regains a high probability of recovery. The impact of this standard on our plant and regulatory assets will be determined by regulatory changes implemented by the DPU and FERC. Based on the transition principles of the DPU's order on industry restructuring and our related plan, which are discussed in the Outlook for the Future section of Management's Discussion and Analysis, we do not expect SFAS 121 to have an adverse impact on our financial position or results of operations in the near term. Our conclusion may change as the actual shape of restructuring of the industry in Massachusetts develops. If recovery of our plant and regulatory assets is not provided, SFAS 121 could require a write-down of these assets.

Note N. Commitments and Contingencies

1. Contractual Commitments

At December 31, 1995, we had estimated contractual obligations for plant and equipment of approximately $35 million.

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both transmission agreements and noncancellable leases for the years after 1995 are as follows:

(in thousands)	
1996	$ 24,908
1997	22,109
1998	19,002
1999	17,408
2000	16,656
Years thereafter	108,417
Total	$208,500

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. The total expense for both lease rentals and transmission agreements was $24.5 million in 1995, $28.6 million in 1994 and $29.8 million in 1993, net of capitalized expenses of $2.7 million in 1995, $2.4 million in 1994 and $5.2 million in 1993.

We also have various outstanding commitments for take or pay and throughput agreements, primarily to supply New Boston Station with natural gas. The fixed and determinable portions of the obligations are $16.1 million in 1996, 1997 and 1998, $24.8 million in 1999 and $13.8 million in 2000. We are also committed to purchase natural gas at market prices. The total expense under these agreements was $13.9 million in 1995, and $6.5 million in 1994 and 1993.

2. 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 on 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, 1995, our portion of these guarantees was approximately $19 million.

3. Yankee Atomic Electric Company

We have a 9.5% stock investment of approximately $2 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.

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 $21 million as of December 31, 1995. 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.

4. 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 $15 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 additional 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 any such assessment.

5. 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. We have also been named as a party in a lawsuit by Subaru of New England, Inc. and Subaru Distributors Corporation. The plaintiffs are claiming certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from New Boston Station. We believe that we have a strong defense in this case. We are also involved in certain other legal matters. We are unable to fully determine a range of reasonably possible litigation costs in excess of amounts previously accrued, although based on the information currently available, we do not expect that any such additional costs will have a material impact on our financial condition. However, additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

6. Hazardous Waste

We own or operate approximately 40 properties where oil or hazardous materials were previously spilled or released. 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 approximately 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, 1995, 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 that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

Note O. 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 on our consolidated income statements. Information relating to these contracts as of December 31, 1995, is as follows:

				proportionate share (in thousands)		
		Units of Capacity Purchased (a)				
Generating Unit	Contract Expiration Date	%	MW	1995 Minimum Debt Service	1995 Interest Portion of Minimum Debt Service	Debt Outstanding Through Cont. Exp. Date
Canal Unit 1	2001	25.0	139	$ 1,122	$ 349	$ 3,400
Mass. Bay Transportation Authority - 1	2005	100.0	34	(b)	(b)	(b)
Connecticut Yankee Atomic	2007	9.5	55	2,646	1,786	13,857
Ocean State Power – Unit 1	2010	23.5	67	4,819	3,318	20,749
Ocean State Power – Unit 2	2011	23.5	66	4,090	3,049	17,228
Northeast Energy Associates	(c)	(c)	219	(c)	(c)	(c)
L'Energia	2013	73.0	64	(d)	(d)	(d)
MassPower (e)	2013	44.3	117	12,217	7,662	81,983
Mass. Bay Transportation Authority - 2	2019	100.0	34	(f)	(f)	(f)
Total			795	$ 24,894	$ 16,164	$ 137,217

(a) The Northeast Energy Associates contract represents 5.9% of our total system generation capability. The remaining units listed above represent 15.6% 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 1995 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 1995 were approximately $127 million.

(d) We pay for this energy based on a price per kWh actually received. The total charges under this contract for 1995 were approximately $25 million.

(e) Payments for this contract 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 1995 were approximately $49 million.

(f) The second Massachusetts Bay Transportation Authority contract started in June 1995. Capacity payments under this contract do not begin until 2003. At that time we will be required to pay $84.57 per kilowatt-year times the qualified capacity plus incremental operating maintenance and fuel costs.

Our total fixed and variable costs for these contracts in 1995, 1994 and 1993 were approximately $283 million, $286 million and $225 million, respectively. Our minimum fixed payments under these contracts for the years after 1995 are as follows:

(in thousands)	
1996	$ 106,649
1997	103,682
1998	105,778
1999	105,258
2000	103,676
Years thereafter	1,187,672
Total	$ 1,712,715
Total present value	$ 883,409

2. Long-Term Power Sales

In addition to wholesale power sales, 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.

Report of Independent Accountants

To the Stockholders and Directors of Boston Edison Company

We have audited the accompanying consolidated balance sheets of Boston Edison Company and subsidiaries (the Company) as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1995. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1995 and 1994, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

Coopers & Lybrand L.L.P.

Boston, Massachusetts
January 25, 1996

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 (a)
1995					
First quarter	$379,678	$ 47,610	$ 20,202	$16,300	$ 0.36
Second quarter	380,828	55,683	26,137	22,247	0.48
Third quarter	498,554	102,695 (b)	72,368 (b)	68,478 (b)	1.46 (b)
Fourth quarter	369,443	21,412 (b)	(6,397)(b)	(10,286)(b)	(0.21)(b)
1994					
First quarter	$376,935	$ 45,891	$ 19,812	$15,850	$ 0.35
Second quarter	368,245	50,812	23,982	20,031	0.44
Third quarter	448,179	96,880	70,[illegible]82	66,256	1.46
Fourth quarter	351,376	34,895	11,046	7,120	0.16

(a) Based on the weighted average number of common shares outstanding during the quarter.

(b) As discussed in Note F to the Consolidated Financial Statements, we incurred a $34 million pre-tax charge related to our corporate restructuring over the third and fourth quarters of 1995. Amounts excluding the restructuring charge are as follows:

	Operating Income	Net Income	Balance Available for Common Stock	Earnings Per Average Common Share
1995				
Third quarter	$ 107,779	$77,452	$73,562	$ 1.57
Fourth quarter	36,991	9,182	5,293	0.11

Certain reclassifications were made to the data reported in prior periods to conform with the current method of presentation.

Selected Quarterly Stock Data

Following are the reported high and low sales prices of our common stock on the New York Stock Exchange as reported daily in the *Wall Street Journal* for each of the quarters in 1995 and 1994 and the dividends declared per share during each of those quarters:

	1995			1994		
	High	Low	Dividends	High	Low	Dividends
First quarter	$25 1/2	$23 1/8	$0.455	$29 7/8	$26	$0.440
Second quarter	27	23 3/8	0.455	29 1/8	25 1/4	0.440
Third quarter	27 1/2	24 1/2	0.455	27 5/8	22 3/4	0.440
Fourth quarter	29 1/2	26 3/4	0.470	24 1/4	21 1/2	0.455

Selected Consolidated Operating Statistics (Unaudited)

	1995	1994	1993	1992	1991
Capacity - MW:					
New Boston Station	**760**	760	760	760	760
Pilgrim Station	**669**	669	670	670	670
Mystic Station	**1,005**	1,006	1,006	1,005	1,015
W.F. Wyman Unit 4	**36**	36	36	36	36
Jet turbines	**284**	287	283	281	281
Total (a)	**2,754**	2,758	2,755	2,752	2,762
Contract purchases	**1,274**	1,035	938	1,157	1,293
Contract sales	**(340)**	(373)	(283)	(303)	(293)
Net capability at year-end	**3,688**	3,420	3,410	3,606	3,762
Net capability at peak - MW	**3,466**	3,484	3,663	3,587	3,695
Capability responsibility to NEPOOL at peak - MW	**3,306**	3,306	3,190	3,396	3,311
Edison territory:					
Hourly peak - MW	**2,785**	2,798	2,662	2,545	2,652
Load factor	**60.0%**	58.9%	60.5%	62.5%	60.0%
Generating station economy (BTU/net kWh)	**10,348**	10,408	10,345	10,234	10,331
Average cost of fuel (Company) - $ per million BTU:					
Fossil	**2.358**	2.321	2.504	2.467	2.402
Nuclear	**0.432**	0.501	0.507	0.522	0.562
Composite	**1.581**	1.613	1.620	1.669	1.805
Capability (net kW):					
Fossil	**85%**	84%	84%	81%	81%
Nuclear	**15%**	16%	16%	19%	19%
Generation (system kWh excluding interchange):					
Fossil	**73%**	75%	68%	69%	70%
Nuclear	**27%**	25%	32%	31%	30%
Utility plant ($ in 000's):					
Expenditures	**$ 180,822**	$ 198,771	$ 246,774	$ 213,827	$ 202,589
Retirements	**48,111**	45,673	34,147	34,036	30,333
Accumulated depreciation	**1,439,996**	1,344,452	1,258,359	1,177,294	1,097,991
Depreciable plant	**4,235,347**	3,994,212	3,841,752	3,567,160	3,488,269
Number of utility employees at year-end	**3,590** (b)	4,026	4,397	4,540	4,637

(a) Winter capability audit results
(b) At January 1, 1996

Certain reclassifications were made to the data reported in prior years to conform with the method of presentation used in 1995.

Selected Consolidated Sales Statistics (Unaudited)

	1995	1994	1993	1992	1991
Electric energy (kWh in thousands):					
Sources (system output):					
Generated	**10,537,114**	9,428,931	9,787,092	11,679,824	10,602,110
Purchased	**5,446,542**	5,920,065	5,326,224	5,449,225	4,651,101
New England Power Pool	**1,513,467**	1,535,335	1,575,310	932,121	1,274,522
Total	**17,497,123**	16,884,331	16,688,626	18,061,170	16,527,733
Disposition:					
Commercial	**7,604,841**	7,478,631	7,263,358	7,178,281	7,143,484
Residential	**3,563,626**	3,534,372	3,477,870	3,413,252	3,386,681
Industrial	**1,538,218**	1,539,385	1,580,969	1,671,564	1,685,184
Other (a)	**131,626**	130,721	145,242	292,510	279,540
Total retail sales	**12,838,311**	12,683,109	12,467,439	12,555,607	12,494,889
Wholesale and contract sales (a)	**2,655,620**	2,367,589	2,272,669	2,517,247	1,660,082
New England Power Pool	**884,336**	725,439	877,978	1,898,059	1,252,797
Total system	**16 378,267**	15,776,137	15,618,086	16,970,913	15,407,768
Miscellaneous usage	**1,118,856**	1,108,194	1,070,540	1,090,257	1,119,965
Total	**17,497,123**	16,884,331	16,688,626	18,061,170	16,527,733
Kilowatthours - annual growth:					
Commercial	**1.7 %**	3.0 %	1.2 %	0.5 %	(0.5)%
Residential	**0.8**	1.6	1.9	0.8	(1.2)
Industrial	**(0.1)**	(2.6)	(5.4)	(0.8)	(3.4)
Other	**0.7**	(10.0)	(50.3)	4.6	1.6
Total retail sales (a)	**1.2**	1.7	(0.7)	0.5	(1.0)
Wholesale and contract sales	**12.2**	4.2	(9.7)	51.6	(0.8)
New England Power Pool	**21.9**	(17.4)	(53.7)	51.5	(33.5)
Total system	**3.8 %**	1.0 %	(8.0)%	10.1 %	(4.8)%
Electric operating revenues by class:					
Commercial	**50%**	50%	49%	48%	48%
Residential	**28%**	28%	28%	27%	27%
Industrial	**9%**	9%	10%	10%	10%
Wholesale and contract	**11%**	11%	12%	13%	13%
Other	**2%**	2%	1%	2%	2%
Retail revenue per kWh	**11.08 ¢**	10.68 ¢	10.33 ¢	9.55 ¢	9.27 ¢
Average number of customers	**653,757**	655,707	651,141	646,215	642,967

(a) Effective February 1993 a former retail customer became a wholesale customer as allowed under Massachusetts state law. Excluding the effect of this customer's change in status, total retail sales increased 2.0% in 1994 and 1.2% in 1993.

Selected Consolidated Financial Statistics (Unaudited)

	1995	1994	1993	1992	1991
Operating revenues (000)	**$1,628,503**	$1,544,735	$1,482,159	$1,411,753	$1,354,501
Balance for common (000)	**$ 96,739**	$ 109,257	$ 102,513	$ 90,748	$ 77,059
Per common share:					
Earnings	**$ 2.52** (a)	$ 2.41	$ 2.28	$ 2.10	$ 1.96
Dividends declared	**$ 1.835**	$ 1.775	$ 1.715	$ 1.655	$ 1.595
Dividends paid	**$ 1.82**	$ 1.76	$ 1.70	$ 1.64	$ 1.58
Book value	**$ 20.61**	$ 20.11	$ 19.42	$ 18.77	$ 17.92
Operating cash flow	**$ 6.81**	$ 8.12	$ 6.58	$ 6.80 (b)	$ 5.50 (b)
Payout ratio	**72%** (a)	73%	75%	78%	81%
Return on average common equity	**12.2%** (a)	12.1%	11.9%	11.5%	11.3%
Year-end dividend yield	**6.4%**	7.6%	5.9%	6.2%	6.6%
Fixed charge coverage (SEC)	**2.38**	2.46	2.22	1.89	1.83
Capitalization:					
Total debt	**54%**	56%	57%	56%	58%
Preferred equity	**8%**	9%	9%	9%	10%
Common equity	**38%**	35%	34%	35%	32%
Long-term debt (000)	**$1,160,223**	$1,156,617	$1,272,497	$1,091,073	$1,136,765
Mandatory redeemable preferred stock (000)	**$ 94,000**	$ 96,000	$ 98,000	$ 98,000	$ 100,000
Total assets (000)	**$3,643,849**	$3,616,576	$3,476,601	$3,294,212	$3,098,742
Internal generation after dividends (000)	**$ 184,492**	$ 217,030	$ 194,209	$ 204,248	$ 193,019
Plant and nuclear fuel expenditures (000)	**$ 194,443**	$ 220,705	$ 253,265	$ 231,025	$ 214,213
Internal generation	**95%**	98%	77%	88%	90%
Common shares outstanding:					
Weighted average	**46,5[illegible],662**	45,337,661	44,959,050	43,143,953	39,347,824
Year-end	**48,063,178**	45,535,477	45,129,227	44,763,055	42,047,356
Stock price:					
High	**29 1/2**	29 7/8	32 5/8	28 1/4	24 7/8
Low	**23 1/8**	21 1/2	26 3/8	22 1/8	18 1/4
Year-end	**29 1/2**	24	29 3/4	27 1/2	24 3/4
Year-end market value (000)	**$1,416,094**	$1,092,851	$1,342,595	$1,230,984	$1,040,672
Trading volume (shares)	**23,078,900**	25,095,100	18,729,400	26,460,900	17,464,300
Market/book ratio (year-end)	**1.43**	1.19	1.53	1.47	1.38
Price/earnings ratio (year-end)	**11.7** (a)	10.0	13.0	13.1	12.6

(a) Amounts including $34 million pre-tax restructuring charge:

Earnings	**$ 2.08**
Payout ratio	**88%**
Return on average common equity	**10.0%**
Price/earnings ratio	**14.2**

(b) Excludes effect of rate and contract settlements.

Certain reclassifications and recalculations were made to the data reported in prior years to conform with the method of presentation used in 1995.

Officers

Thomas J. May, Chairman of the Board, President and Chief Executive Officer

E. Thomas Boulette, Senior Vice President - Nuclear

L. Carl Gustin, Senior Vice President - Corporate Relations

John J. Higgins, Jr., Senior Vice President - Human Resources

Douglas S. Horan, Senior Vice President and General Counsel

James J. Judge, Senior Vice President and Treasurer

Ronald A. Ledgett, Senior Vice President - Fossil

Alison Alden, Vice President - Sales & Service

William N. Dimoulas, Vice President - Information Systems

Richard S. Hahn, Vice President - Technology Research & Development

Leon J. Olivier, Vice President - Nuclear Operations and Station Director

Robert A. Ruscitto, Vice President - Field Service and Electric Delivery

Robert J. Weafer, Jr., Vice President - Finance, Controller and Chief Accounting Officer

Theodora S. Convisser, Clerk of the Corporation

Donald Anastasia, Assistant Treasurer

Wayne R. Frigard, Assistant Clerk of the Corporation

Directors

a,d William F. Connell, Chairman and Chief Executive Officer, Connell Limited Partnership (metals recycling and processing and industrial production)

d,f Gary L. Countryman, Chairman of the Board and Chief Executive Officer, Liberty Mutual Insurance Company

a,e,f Thomas G. Dignan, Jr., Partner, Ropes & Gray (law firm)

b,c,d Charles K. Gifford, Chairman, President and Chief Executive Officer, Bank of Boston Corporation (bank holding company) and The First National Bank of Boston

b,f Nelson S. Gifford, Principal, Fleetwing Capital (venture investments)

a,e Kenneth I. Guscott, General Partner, Long Bay Management Company (real estate development)

a,b,c Matina S. Horner, Executive Vice President, Teachers Insurance and Annuity Association and College Retirement Equities Fund

a,c Thomas J. May, Chairman of the Board, President and Chief Executive Officer, Boston Edison Company

b,d Sherry H. Penney, Chancellor, University of Massachusetts at Boston

e,f Bernard W. Reznicek, Dean, College of Business Administration, Creighton University and former Chairman of the Board and Chief Executive Officer, Boston Edison Company

e,f Herbert Roth, Jr., Former Chairman of the Board and Chief Executive Officer, LFE Corporation (traffic and industrial control systems)

e,f Stephen J. Sweeney, Former Chairman of the Board and Chief Executive Officer, Boston Edison Company

b,c,d Paul E. Tsongas, Partner, Foley Hoag & Eliot (law firm)

a Member of Executive Committee

b Member of Audit, Finance and Risk Management Committee

c Member of Pricing Committee

d Member of Executive Personnel Committee

e Member of Nuclear Oversight Committee

f Member of Capital Investment Committee

Important Shareholder Information

Shareholder Inquiries

If you have questions concerning your dividend payments, the Dividend Reinvestment and Common Stock Purchase Plan, direct deposit service, transfer procedures or other stock account matters, please contact our stock transfer agent at the following address:

The First National Bank of Boston
c/o Boston EquiServe
Shareholder Services Division
Mail Stop: 45-02-09
P.O. Box 644
Boston, MA 02102-0644

Toll Free Phone: 1-800-736-3001

If you are submitting documents requesting a transfer, address change or account consolidation, please use this same address with **Mail Stop: 45-01-05**. If you would like to contact the bank by telephone call **617-575-3100**.

Dividend Payments Dates

Common and Preferred
1st of February, May, August and November

Tax Status of 1995 Dividends

Generally, unless you are subject to certain exemptions, all dividends on our common or preferred stock are to be considered 100% taxable.

Stock Symbol and Exchange Listings

Ticker Symbol: BSE
New York and Boston stock exchanges

1996 Annual Shareholders Meeting

All shareholders are invited to attend our Annual Meeting on Wednesday, May 8, 1996, at 11:00 A.M. at the Sheraton Boston Hotel and Towers.

Dividend Payments - Direct Deposit Service

Shareholders receiving dividend checks can arrange for electronic direct deposit. Transfers are made on the dividend payment dates and confirmation statements are mailed to shareholders. To take advantage of this convenient program, contact our stock transfer agent as noted above.

Dividend Reinvestment and Common Stock Purchase Plan

In 1995, we modified and improved our Dividend Reinvestment and Common Stock Purchase Plan (the plan). It is available to our common and preferred shareholders, our residential electric customers and employees. Participants do not pay brokerage fees or commissions related to the purchase of shares. Some important features of the plan are as follows:

- Optional cash payments invested monthly
- $50 per month minimum not to exceed $40,000 per calendar year
- Safekeeping of common stock certificates

Beneficial owners of our stock whose shares are registered in names other than their own (e.g., a broker or bank nominee) must arrange participation with the record holder. If for any reason you are unable to arrange participation with your broker or bank nominee, you must become a record holder by having the shares transferred to your own name.

If you are interested in receiving a prospectus to learn more about this plan, or if you have questions on an existing account, contact our stock transfer agent.

Safekeeping Program (New)

Shareholders who are participants in the Dividend Reinvestment and Common Stock Purchase Plan can transfer their common stock certificates into their plan account for safekeeping. Dividends on those shares will be reinvested automatically like any other shares held in the plan. To continue receiving cash dividends, you must hold your shares in certificate form. For additional information, contact our stock transfer agent.

SEC Form 10-K

Stockholders may obtain a copy of our annual report to the Securities and Exchange Commission on Form 10-K, by contacting our Investor Relations Department.

Quarterly Report to Shareholders

Beneficial owners of our stock whose shares are registered in names other than their own may obtain copies of our Quarterly Reports to Shareholders by contacting our Investor Relations Department. Note that the Annual Report will continue to be mailed to beneficial owners directly by their bank or broker.

Company Contact

Theodora S. Convisser
Clerk of the Corporation

Investor Relations Contacts

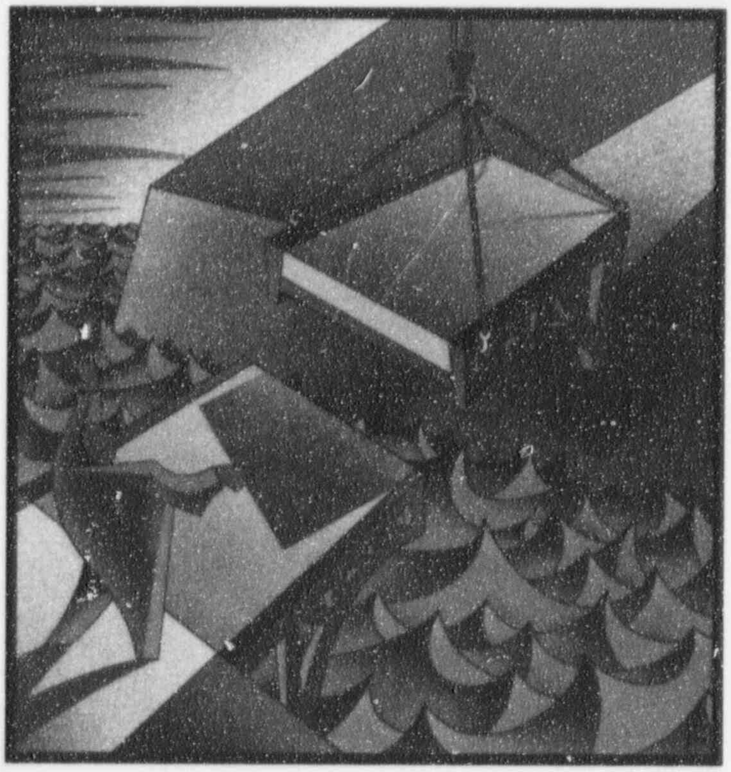
Philip J. Lembo
Director, Investor Relations
(617) 424-3562
or
Jean M. Carella
Investor Relations Specialist
(617) 424-2658

Email Address

ir@bedison.com

General Offices

800 Boylston Street
Boston, MA 02199-8003



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Boston Edison
800 Boylston Street
Boston, Massachusetts 02199-8003

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, 1995

OR

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

For the transition period from _________ to _________

Commission file number 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 29, 1996 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: $1,328,730,345.

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 29, 1996
Common Stock, $1 par value	48,098,836 shares

DOCUMENTS INCORPORATED BY REFERENCE

Part	Document
III	Portions of definitive proxy statement dated March 28, 1996 for Annual Meeting of Stockholders to be held May 8, 1996.

Boston Edison Company

Form 10-K Annual Report

December 31, 1995

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 electric demand side management programs.

The Company has an unregulated subsidiary, Boston Energy Technology Group (BETG), in which it has authority from the Massachusetts Department of Public Utilities (DPU) to invest up to $45 million. This wholly owned subsidiary engages primarily in energy conservation services and the production of water treatment systems. In 1996 BETG entered into a joint venture to build a series of ice-based cooling systems. BETG's investment in this joint venture, Northwind Boston, is not material. 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, including 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 1995 the Company served an average of 654,000 customers. The Company also supplies electricity at wholesale for resale to other utilities and municipal electric departments. Electric operating revenues by class for the last three years consisted of the following:

	1995	1994	1993
Retail electric revenues:			
Commercial	50%	50%	49%
Residential	28%	28%	28%
Industrial	9%	9%	10%
Other	2%	2%	1%
Wholesale and contract revenues	11%	11%	12%

Sources and Availability of Fuel

The Company owns two stations whose generating units have the ability to burn oil, natural gas or both, one nuclear power station and ten combustion turbine generators. Refer also to 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)				
	1995	1994	1993	1992	1991	1995	1994	1993	1992	1991
Oil	17.5	27.8	31.3	33.7	42.8	2.66	2.35	2.38	2.40	2.60
Gas	39.9	31.6	24.3	25.7	24.9	2.20	2.28	2.67	2.55	2.08
Nuclear	42.6	40.6	44.4	40.6	32.3	0.43	0.50	0.51	0.52	0.56

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.

A portion 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. The Company is currently required to fuel New Boston Station exclusively by natural gas, except in certain emergency circumstances, as part of a 1991 consent order with the Massachusetts Department of Environmental Protection (DEP). The Company has arrangements for a firm supply of natural gas to run the station at a minimum level and is developing a least-cost plan for operating beyond this minimum level which principally utilizes 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 the 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, greater than half of the Company's annual earnings typically occurs in the third quarter. Refer also to the 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. Competitive pressures on the electric utility industry have increased due to a variety of factors, including legislative and regulatory proceedings at both federal and state levels and changes in customer expectations. The trend is toward promotion of increased competition through modified regulation of the industry.

To date the effects of competition have been most prominent in the wholesale electric market. In response to increased competition from other electric utilities and nonutility generators to sell electricity for resale, the Company secured long-term power supply agreements with its six wholesale customers that set rates through 2002 and beyond.

As discussed in the *Competition* section of Item 7, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) in March 1995 addressing open transmission access and recovery of previously incurred costs. The provisions in the NOPR provide a framework for significant changes in the electric utility industry.

Direct competition with other electric utilities and other energy suppliers for retail electricity sales is still subject to certain limitations. 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.

Despite the limitations on direct competition, the Company has been experiencing some forms of increased competition in the retail electric market. Competition currently exists with alternative fuel suppliers as customers are able to substitute natural gas, steam or oil for electricity for heating or cooling purposes. In addition, current legislation allows industrial and large commercial customers to own and operate their own electric generating units. Large facilities may also factor the cost of electricity into their decisions to relocate to new service territories. Electric utilities are thus under increasing pressure to discount rates.

In August 1995 the DPU issued an order on restructuring of the electric utility industry. The order provides for Massachusetts-based electric utilities to restructure their operations to encourage more competition for customers. Refer to the *Competition* section of Item 7 for a discussion of the DPU order and the Company's involvement in the restructuring proceedings.

In addition to its involvement in the DPU's restructuring proceedings, the Company is actively responding to the current and anticipated changes in the industry in several ways. In 1995 the Company reorganized into separate business units and reduced its workforce in order to strengthen its competitiveness as discussed in Note F to the Consolidated Financial Statements. It also continued to develop customer alliances and provided economic development rates to some customers. In addition, the Company currently has a special lower rate available for a small number of large manufacturing customers on a limited basis and recently implemented a one-year pilot program that uses a competitive market index to set electric rates for a limited number of customers. These actions all signify the Company's commitment to be a competitively priced, reliable provider of energy.

Research Activities

The Company actively participates in several industry sponsored research activities. Related expenditures, included in other operations and maintenance expense on the consolidated income statement in Item 8, were not material in 1995.

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 environmental-related capital expenditures for the years 1996 through 2000 are currently expected to total $17 million, including $4.5 million in 1996 and $3.5 million in 1997. Additional expenditures could be required as changes in environmental requirements occur.

The Company is required by the DEP to clean up approximately 40 properties that it owns or operates in which hazardous materials were previously spilled

or released. In addition, the Company has exposure to potential joint and several liability for the cleanup of approximately ten multi-party hazardous waste sites in Massachusetts and other states where it is alleged to have generated, transported or disposed of hazardous waste at the sites. 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 continue to exist regarding the ultimate disposal of both the spent nuclear fuel and LLW. Refer to Note E to the Consolidated Financial Statements in Item 8 for further discussion regarding spent nuclear fuel and LLW disposal.

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 fuel-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 is 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. The Company has the required discharge permits for each of its electric generating stations.

Public concern continues 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 3,518 full-time and 26 part-time utility employees as of January 1, 1996, 2,342 of which are represented by two locals of the Utility Workers Union of America, AFL-CIO. The locals' labor contracts are effective through 2000. BETG had 46 full-time employees.

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

Refer to *Principal Products and Services* of this item 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 FERC 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 that 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 1994 and October 1995. 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, 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.

The Company also owns 9.5% of the common stock of Connecticut Yankee Atomic Power Company, which owns a nuclear generating unit. Northeast Utilities, the majority owner of Connecticut Yankee, operates the unit. In March 1996 the

NRC ordered Northeast Utilities to submit a plan within 30 days verifying operational compliance with licensing documentation at the Connecticut Yankee unit and another unit owned and operated by Northeast Utilities, or risk having the plants shut down. This order follows noncompliances discovered at two of Northeast Utilities' other nuclear units. The Company is unable to determine at this time what the results of the NRC order will be on the operations of the Connecticut Yankee unit, or what the impact would be on the Company if the unit were to be shut down.

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 1996 through 2000 are as follows:

(in thousands)	1996	1997	1998	1999	2000
Plant expenditures	$160,000	$140,000	$130,000	$120,000	$110,000
Nuclear fuel expenditures	48,000	0	27,000	13,000	29,000
AFUDC (1)	2,000	2,000	2,000	2,000	2,000
Long-term debt	101,600	101,600	101,600	1,600	166,600
Preferred stock sinking fund	2,000	2,000	2,000	2,000	2,000

(1) Excludes AFUDC on nuclear fuel.

The Company conducts a continuing review of its capital expenditure and financing programs. These programs and, therefore, the estimates shown above are subject to revision due to changes in regulatory requirements, environmental standards, availability and cost of capital, interest rates and other assumptions.

Plant expenditures in 1995 were $181 million and consisted primarily of additions to the Company's transmission and distribution systems and nuclear generation facility. Significant projects included spending of $20 million for the replacement of the main turbine rotors at Pilgrim Station and $17 million for the replacement of electric system property.

In 1994 the DPU approved the Company's financing plan to issue up to $500 million of securities through 1996 using the proceeds to refinance short and long-term securities and for capital expenditures. Refer to Notes J and K 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 consisted of the following:

Unit	Location	Capacity[a]	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 generator		14	Fossil	1969
Combustion turbine generators (nine)	Various	284	Fossil	1966-1971

(a) In MW based on winter capability audit results.

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 also owns approximately 6% of 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 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, 1995, 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 46 transmission or combined transmission and distribution substations with transformer capacity of 10,612 megavolt amperes (MVA), 69 distribution substations with transformer capacity of 1,143 MVA and 18 primary network units with 88 MVA capacity. In addition, high tension service was delivered to 237 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 one proceeding before the EFSB, which concerns proposed transmission and station facilities in Hopkinton and Milford, Massachusetts.

Long-Term Power Contracts

Refer to Note O 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.

Utility Purchase Contracts:

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 unit. 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 has a contract to purchase 9.5% of Connecticut Yankee's nuclear generating 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 533 MW of capacity and associated energy from non-utility generators. These purchases are from Ocean State Power, Northeast Energy Associates, L'Energia and MassPower. The Company also purchases power from two small hydro-electric facilities.

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 and other electricity suppliers 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 1995-1996 winter and 1995 summer peak loads:

	December 11, 1995 (winter 1995-96)	August 16, 1995 (summer 1995)
NEPEX utilities installed capacity:		
Seasonal maximum rating	27,187 MW	25,637 MW
Seasonal normal rating	26,839 MW	25,353 MW
NEPEX peak load	19,167 MW	20,486 MW
Company territory peak load	2,458 MW	2,785 MW

The Company's net capacity was 3,667 MW at its winter peak and 3,445 MW at its summer peak. Its corresponding NEPOOL capacity obligations were estimated to be 3,341 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 transmission 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. At December 31, 1995, the Company's portion of these guarantees was approximately $19 million.

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 (US District Court) 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. The

Company has also been named as a party in a lawsuit filed in both the US District Court and the Massachusetts Norfolk Superior Court by Subaru of New England, Inc. and Subaru Distributors Corporation in 1992. The plaintiffs are claiming certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from New Boston Station. The Company believes that it has a strong defense in this case. It is also involved in certain other legal matters. The Company is unable to fully determine a range of reasonably possible litigation costs in excess of amounts previously accrued, although based on the information currently available, it does not expect that any such additional costs will have a material impact on its financial condition. However, additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

Also refer to the *Environmental* section in Item 7 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 1995.

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, 1996 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, 48 Chairman of the Board, President and Chief Executive Officer	Chairman of the Board, President and Chief Executive Officer (since 1995), Chairman of the Board and Chief Executive Officer (1994-1995), President and Chief Operating Officer (1993-1994) and Executive Vice President (1990-1993); Director (since 1991) Chairman of the Board and Chief Executive Officer and Director, Harbor Electric Energy Company, Boston Energy Technology Group, TravElectric Services Corp. and Ener-G-Vision, Inc.; Chairman of the Board and Director, REZ-TEK International Corp. and Coneco Corp.
E. Thomas Boulette, 53 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
L. Carl Gustin, 52 Senior Vice President - Corporate Relations	Senior Vice President - Corporate Relations (since 1995), Senior Vice President - Marketing & Corporate Relations (1989-1995)
John J. Higgins, Jr., 63 Senior Vice President - Human Resources	Senior Vice President - Human Resources (since 1990)

Name, Age and Position	Business Experience During Past Five Years
Douglas S. Horan, 46 Senior Vice President and General Counsel	Senior Vice President and General Counsel (since 1995), Vice President and General Counsel (1994-1995), Deputy General Counsel (1991-1994) and Associate General Counsel (1986-1991) Director and General Counsel, Harbor Electric Energy Company; Director, Boston Energy Technology Group
James J. Judge, 40 Senior Vice President and Treasurer	Senior Vice President and Treasurer (since 1995), Assistant Treasurer (1989-1995) and Director - Corporate Planning (1993-1995) Senior Vice President, Treasurer and Director, Harbor Electric Energy Company and Boston Energy Technology Group; Director, Ener-G-Vision, Inc., TravElectric Services Corp. and REZ-TEK International Corp.
Ronald A. Ledgett, 57 Senior Vice President - Fossil	Senior Vice President - Fossil (since 1995), Senior Vice President - Power Delivery (1991-1995) and Director, Special Projects (1989-1991)
Alison Alden, 47 Vice President - Sales & Service	Vice President - Sales & Service (since 1993) and Director - Organization Development (1990-1993) Director, Harbor Electric Energy Company, Boston Energy Technology Group and Coneco Corp.
Robert A. Ruscitto, 51 Vice President - Field Service and Electric Delivery	Vice President - Field Service and Electric Delivery (since 1995), Vice President - Electric Customer Service (1994-1995), General Manager, Electric Customer Service (1992-1994) and Manager, Metropolitan Transmission & Distribution Department (1990-1992)

Name, Age and Position	Business Experience During Past Five Years
Robert J. Weafer, Jr., 49 Vice President - Finance, Controller and Chief Accounting Officer	Vice President - Finance, Controller and Chief Accounting Officer (since 1991), Controller (1988-1991) and Chief Accounting Officer (1983-1991)
Theodora S. Convisser, 48 Clerk of the Corporation	Clerk of the Corporation (since 1986) and Assistant General Counsel (since 1984) Clerk, Harbor Electric Energy Company, Boston Energy Technology Group, TravElectric Services Corp., Ener-G-Vision, Inc., REZ-TEK International Corp. and Coneco Corp.

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 1995 and 1994:

	1995		1994	
	High	Low	High	Low
First quarter	$25 1/2	$23 1/8	$29 7/8	$26
Second quarter	27	23 3/8	29 1/8	25 1/4
Third quarter	27 1/2	24 1/2	27 5/8	22 3/4
Fourth quarter	29 1/2	26 3/4	24 1/4	21 1/2

(b) Holders

As of December 31, 1995, the Company had 38,205 holders of record of its common stock.

(c) Dividends

Following are the dividends declared per share of common stock for each of the quarters in 1995 and 1994:

	1995	1994
First quarter	$0.455	$0.440
Second quarter	0.455	0.440
Third quarter	0.455	0.440
Fourth quarter	0.470	0.455

(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, 1995:

Ratio of earnings to fixed charges	2.38
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.00

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).

	1995	1994	1993	1992	1991
Operating revenues	$1,628,503	$1,544,735	$1,482,159	$1,411,753	$1,354,501
Net income	112,310	125,022	118,218	107,298	94,670
Earnings per common share	2.52(a)	2.41	2.28	2.10	1.96
Total assets	3,643,849	3,616,576	3,476,601	3,294,212	3,098,742
Long-term debt	1,160,223	1,136,617	1,272,497	1,091,073	1,136,765
Redeemable preferred/ preference stock	217,000	219,000	221,000	221,000	221,333
Cash dividends declared per common share	1.835	1.775	1.715	1.655	1.595

(a) Excludes $0.44 per share restructuring charge.

Certain reclassifications were made to the data reported in prior years to conform with the method of presentation used in 1995.

Item 7. Management's Discussion and Analysis

Rate Regulation

The rates we charge our retail customers are regulated by our state regulators, the Massachusetts Department of Public Utilities (DPU). In 1992 the DPU 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 two annual base rate increases of $29 million effective November 1993 and November 1994 and an annual performance adjustment charge effective November 1992 through October 2000. The performance adjustment charge varies annually based on the performance of Pilgrim Nuclear Power Station. This charge is further described in the Electric Sales and Revenues section.

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.

We did not make a base rate filing upon the expiration of the 1992 settlement agreement, therefore base rates currently remain in effect at their 1995 levels.

In February 1996 we filed an industry restructuring plan with the DPU in response to its August 1995 order on restructuring the electric utility industry. This plan is expected to lead to negotiations with intervening parties that will result in an unbundling of our currently integrated monopoly business into a separate competitive electric production business and a regulated electric distribution business. Refer to Outlook for the Future for further information regarding the restructuring of the electric utility industry in Massachusetts.

Results of Operations

1995 versus 1994

Earnings per common share were $2.08 in 1995 and $2.41 in 1994. Earnings in 1995 reflect a one-time charge of $34 million ($20.7 million net of tax, or $0.44 per share) associated with our corporate restructuring. The charge reflects the costs of early retirement and severance programs implemented as part of our organizational streamlining and reorganization into business units. Excluding the one-time charge, earnings per common share were $2.52 in 1995, an increase of 4.6% over 1994. This increase is due to the $29 million annual retail base rate increase effective November 1994, the ending of amortization of deferred cancelled nuclear costs in 1994, a 1.2% increase in retail kWh sales and lower revenue reserve provisions. These positive impacts were partially offset by higher income tax, property tax, nuclear outage amortization and employee benefit expenses, and an award received on an eminent domain case in 1994.

Operating revenues

Operating revenues increased 5.4% over 1994 as follows:

(in thousands)	
Retail electric revenues	$59,419
Demand side management revenues	8,783
Wholesale and other revenues	11,126
Short-term sales revenues	4,440
Increase in operating revenues	$83,768

Retail electric revenues increased $59 million. Approximately $28 million of the increased revenues was due to the November 1994 base rate increase and approximately $11 million was due to the increase in retail kWh sales. Fuel and purchased power revenues increased $11 million as a result of the timing effect of fuel and purchased power cost recovery. However, these higher revenues are offset by higher fuel and purchased power expenses and have no net effect on earnings. Performance revenues, which vary annually based on the operating performance of Pilgrim Station, increased $9 million primarily due to a higher performance rate effective in 1995 and a 17% increase in generation.

A new annual conservation charge for recovery of demand side management program costs was implemented in February 1995. Under this charge all 1995 program costs were recovered in 1995. This resulted in higher DSM revenues and expenses than in prior years when certain program costs were capitalized for recovery over six years.

The net increase in wholesale and other revenues is primarily due to a $10 million decrease in revenue reserve provisions, which are primarily related to wholesale customer contract issues.

The increase in short-term sales revenues is due to higher short-term sales resulting from higher generating availability in 1995. Revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and therefore have no net effect on earnings.

Operating expenses

Total fuel and purchased power expenses increased $22 million primarily due to the timing effect of fuel and purchased power cost collection. Excluding the timing effect, fuel expense increased 5% due to an 8% increase in fossil station generation while purchased power expense was unchanged. Fuel and purchased power expenses are substantially all recoverable through fuel and purchased power revenues.

Other operations and maintenance expense increased 0.9% over 1994. Employee benefit expenses increased primarily due to higher postretirement benefit expenses recorded in accordance with the 1992 settlement agreement. We also incurred higher administrative costs in positioning the company for changes in the industry, which were offset by lower operating costs in the electric delivery business. Electric generation costs increased only 1% in 1995, primarily due to a refueling and maintenance outage at Pilgrim Station.

The $34 million one-time restructuring charge was incurred over the third and fourth quarters of 1995 as a result of our corporate reorganization announced in July 1995. As part of the reorganization 330 employees elected to retire under enhanced retirement programs and 149 employees whose positions were eliminated became eligible for benefits under a special severance program.

See Note F to the Consolidated Financial Statements for additional information. We expect to achieve ongoing savings as a result of the restructuring, with a payback period of approximately one year.

Depreciation and amortization expense increased due to a higher average depreciable plant balance.

In 1994 we fully expensed the remaining deferred costs of the cancelled Pilgrim 2 nuclear unit.

In the third quarter of 1995 we changed the amortization period of deferred nuclear outage costs to two years from five years as discussed in Note B to the Consolidated Financial Statements. The remaining $9 million of deferred costs allocable to retail customers for refueling outages performed in 1991 and 1993 was written off. Approximately $15 million of deferred costs from the 1995 refueling outage is being amortized over two years.

The increase in demand side management programs expense is related to the increase in DSM revenues. Beginning with the annual conservation charge implemented in February 1995, DSM costs are recovered and expensed primarily in the year incurred. The 1995 expense includes $31 million of 1995 program costs and $14 million of amortization of costs capitalized in 1992 through 1994.

Property and other taxes increased primarily due to higher Boston property taxes resulting from capital additions.

Our effective annual income tax rate for 1995 was 37.1% vs. 31.4% for 1994. The higher rate is the result of a $10 million adjustment to deferred income taxes made in 1994 in accordance with the 1992 settlement agreement.

Other income

The net decrease in other income is primarily due to a $5.7 million gain recognized in 1994 from a court ruling on a 1989 eminent domain taking of certain of our property.

Interest charges

Interest charges on long-term debt increased due to a $125 million debentures issuance in May 1995, partially offset by interest savings from first mortgage bond and debenture redemptions in 1994. Other interest charges increased slightly 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, decreased due to a lower construction work in progress balance and shorter construction periods, partially offset by a higher AFUDC rate related to the higher short-term interest rates.

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 $29 million annual 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 4.2% over 1993 as follows:

(in thousands)	
Retail electric revenues	$62,945
Demand side management revenues	5,056
Wholesale and other revenues	(6,644)
Short-term sales revenues	1,219
Increase in operating revenues	$62,576

Retail electric revenues increased $63 million. The November 1993 and 1994 base rate increases resulted in $29 million of the increased revenues, and approximately $6 million was due to the 2% increase in retail kWh sales. Fuel and purchased power revenues increased $28 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.

Wholesale and other revenues decreased primarily due to an $8.5 million increase in revenue reserve provisions in 1994 related to certain wholesale customer 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.

Other operations and maintenance expense increased 7.4% 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 recorded 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 in 1994 and 1993 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 from the statutory rate by adjustments to deferred income taxes of $10 million in 1994 and $20 million in 1993 made in accordance with the 1992 settlement agreement.

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 certain of our property.

Interest charges

Total interest charges 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 part ally offset by a lower average short-term debt level. AFUDC increased as a result of a higher AFUDC rate related to the higher short-term interest rates.

Electric Sales and Revenues

Electric sales

Retail kWh sales increased 1.2% in 1995 primarily due to the positive effects of a stronger economy on commercial customers. This sector represents approximately 50% of our electric operating revenues.

Demand side management conservation programs are designed to assist customers in reducing electricity use and, therefore, result in lower growth in electricity sales. We receive approval from our state regulators for DSM spending levels and recovery amounts through an annual conservation charge. 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. In 1995 a new annual conservation charge was implemented under which all 1995 program costs were recovered in 1995. 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 are recovering over six years.

Electric revenues

As discussed in the Rate Regulation section, our 1992 settlement agreement provided us with two annual retail base rate increases of $29 million effective in 1993 and 1994 and an eight-year annual performance adjustment charge. We did not make a base rate filing upon the expiration of the settlement agreement in 1995, therefore base rates currently remain in effect at their 1995 levels. Due to our continued commitment to controlling costs and increasing operating efficiencies, maintaining these rate levels in our current regulatory environment is not expected to significantly affect our financial condition or results of operations.

The annual performance adjustment charge provides us with opportunities to improve our financial results. The most significant potential impact of this

performance incentive is based on Pilgrim Station's annual capacity factor. An annual capacity factor between 60% and 68% would provide us with approximately $51 million of revenues in the performance year ended October 1996. For each percentage point increase in capacity factor above 68%, annual revenues will increase by approximately $750,000. For each percentage point decrease in capacity factor below 60% (to a minimum of 35%), annual revenues will decrease by approximately $840,000. Pilgrim's capacity factor for the performance year ending October 1996 is currently expected to be approximately 91%, an increase from the 67% capacity factor achieved in the performance year ended October 1995. There are no major outages scheduled for the current performance year. Pilgrim was out of service in November 1994 and for a 73-day refueling and maintenance outage in 1995. We earned approximately $49 million in revenues related to Pilgrim's capacity factor in the performance year ended October 31, 1995.

Pilgrim Station was shut down for three months in 1994 due to a non-nuclear problem with its electrical generator. Regularly scheduled maintenance work was also performed during the shutdown. The power needs usually met by the station were met by other generating plants or purchased from other suppliers as necessary. We do not believe that the generator damage resulted from actions within our control. Our recovery of the incremental purchased power costs during the outage through fuel and purchased power revenues, however, is subject to review by the DPU under a generating unit performance program.

Liquidity

We meet our capital expenditure cash requirements primarily with internally generated funds. These funds provided for 95%, 98% and 77% of our plant and nuclear fuel expenditures in 1995, 1994 and 1993, respectively. Our current estimate of plant expenditures for 1996 is $160 million. These expenditures will be used primarily to maintain and improve existing transmission and distribution facilities. We expect plant expenditures to remain level or decline slightly from the 1996 amount in the four years thereafter. In addition to capital expenditures we have long-term debt and preferred stock payment requirements of $103.6 million per year in 1996 through 1998, $3.6 million in 1999 and $168.6 million in 2000.

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, the Federal Energy Regulatory Commission (FERC), 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, 1995, we had $126 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. In 1994 the DPU approved our financing plan to issue up to $500 million of securities through 1996 using the proceeds to refinance short and long-term securities and for capital expenditures. Refer to Notes J and K to the Consolidated Financial Statements for specific information relating to our recent financing activities.

Outlook for the Future

Competition

Competitive pressures on the electric utility industry have increased due to a variety of factors, including legislative and regulatory proceedings at both federal and state levels and changes in customer expectations. The trend is

toward promotion of increased competition through modified regulation of the industry.

To date the effects of competition have been most prominent in the wholesale electric market. In response to increased competition from other electric utilities and nonutility generators to sell electricity for resale, we secured long-term power supply agreements with our six wholesale customers that set rates through 2002 and beyond. In 1995, our largest retail customer, the Massachusetts Port Authority (Massport), issued a request for proposals for a wholesale supplier of electricity. We successfully retained Massport as a customer through a ten-year wholesale power supply agreement effective November 1995. We are awaiting approval of this agreement from the FERC.

In March 1995 the FERC issued a Notice of Proposed Rulemaking (NOPR) addressing open transmission access and recovery of previously incurred costs. If approved, the NOPR would require all utilities with transmission systems to file open access tariffs at the FERC, to provide service under those tariffs to transmission customers comparable to service provided to their electric energy customers and to take service under the tariffs for wholesale purchases and sales. The NOPR also supports the full recovery of legitimate and verifiable costs previously incurred under federal and state regulation. The provisions in the NOPR provide a framework for significant changes in the electric utility industry.

We have also been experiencing increased competition in the retail electric market. Competition currently exists with alternative fuel suppliers as customers are able to substitute natural gas, steam or oil for electricity for heating or cooling purposes. In addition, industrial and large commercial customers may pursue options to generate their own electric power or factor the cost of electricity into their decisions to relocate to new service territories. Electric utilities are thus under increasing pressure from these customers to discount rates.

In August 1995 the DPU issued an order on restructuring of the electric utility industry. The order provides for Massachusetts-based electric utilities to restructure their operations to encourage more competition for customers. It also includes the following principles for a restructured electric industry:

- provide the broadest possible customer choice
- provide all customers with an opportunity to share in the benefits of increased competition
- ensure full and fair competition in generation markets
- functionally separate generation, transmission and distribution services
- provide universal service
- support and further the goals of environmental regulation
- rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist

The DPU order also set the following principles to guide the transition from a regulated to a competitive industry structure:

- honor existing commitments
- unbundle rates for generation, transmission and distribution
- reduce rates in the near term
- maintain demand side management programs
- ensure an orderly and quick transition that minimizes customer confusion

The order provides a reasonable opportunity for the recovery of net, nonmitigatable potentially strandable costs (strandable costs), over a period

of up to ten years. These costs include investments in plant that might not be recoverable in a competitive market, liabilities for future decommissioning of nuclear plants, the amounts by which certain purchase power contracts exceed the competitive price for generation, and prudently incurred regulatory assets. We are looking at possibilities for mitigating our potentially strandable costs, including potential revisions to depreciation and amortization periods.

The order establishes only general principles for the transition to a competitive market and does not establish a particular model for the new industry structure. Each of the Massachusetts-based electric utilities is required to develop a plan for moving toward competition consistent with the DPU's order and encouraged to negotiate with all interested parties while doing so. We were one of three companies required to file a restructuring plan in February 1996. Our plan is consistent with the general principles outlined in the order, including unbundled rates for generation, transmission and distribution. It provides for and is based upon full recovery of strandable costs through a nonbypassable access charge. This charge is to be paid by customers as a condition of receiving service over our distribution system, which remains a monopoly function. We expect to enter into negotiations with intervening parties that will result in new rates and performance incentives to be implemented in the new industry structure.

In addition to our involvement in the DPU's restructuring proceedings, we are actively responding to the current and anticipated changes in the industry in several ways. In 1995 we reorganized the company into separate business units in order to strengthen our competitiveness. These business units, Customer, Generating-Fossil, Generating-Nuclear and Corporate Services, were designed to sharpen management focus along our significant lines of operation while maintaining company-wide strategic goals. As a result of enhanced retirement programs and a special severance program offered during this corporate restructuring, we reduced our workforce by 12%. We expect to achieve ongoing savings as a result of the restructuring, with a payback period of approximately one year. We also continued to develop customer alliances and provided economic development rates to some customers. In addition, we currently have a special lower rate available for a small number of large manufacturing customers on a limited basis and we recently implemented a one-year pilot program that uses a competitive market index to set electric rates for a limited number of customers. These actions all signify our commitment to be a competitively priced, reliable provider of energy. We do not expect the economic development rates, the lower manufacturing customer rates or the pilot program to have a significant impact on our financial condition or results of operations.

In the rate-regulated environment based on cost recovery that we have traditionally operated in, we are subject to certain accounting standards that are not applicable to other businesses and industries. The standards allow us to record certain costs as regulatory assets instead of as expenses when incurred when we expect to receive future rate recovery of the costs. We believe that we currently meet the criteria of these standards. In addition to the specifically identified regulatory assets on our consolidated balance sheets, there may be differences in the carrying value of our net utility plant compared to what the amount would have been if we were not subject to rate regulation. These potential differences would be due to differing plant depreciable lives for regulatory and non-regulatory accounting standards. We have not yet fully determined to what extent such differences may exist. The effects of competition and modified regulation could, in the near term, cause us to no longer meet the criteria for application of the regulatory accounting standards for some of our operations. Should this occur we would have to take a noncash write-off of our affected regulatory assets and adjust our affected

plant balances if necessary by recording an addition to depreciation expense at that time. However, the DPU order on industry restructuring provides a reasonable opportunity for recovery of these previously incurred costs, which are also provided for in our related plan. We expect to recover all strandable costs through our distribution system, which we expect will remain rate-regulated, and therefore will continue to meet the criteria of these accounting standards. If it does not continue to be likely that we will recover all our regulatory assets and generating plant costs as our restructuring plan is ultimately finalized, we would have to write off such portions that are no longer probable of recovery in accordance with Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of. See Note M to the Consolidated Financial Statements for information on this new accounting standard. The nonrecovery of specifically identified and other embedded regulatory assets or plant costs could have a material impact on our results of operations and financial condition.

Resource regulation

In this period of transition in the electric utility industry we remain subject to current regulatory requirements. The DPU requires utilities to purchase power from qualifying nonutility generators at prices set through a bidding process. In a continuation of a dispute which originated in 1991, the DPU is currently investigating whether we should again be ordered to negotiate a contract to purchase power from an independent power producer, JMC Altresco, Inc. We have consistently opposed this order since we do not believe we need any new power for several years and the proposed contract would impose excessive costs on our customers. In 1995 we filed a motion to dismiss the matter, which is pending. We also filed testimony comparing the cost of Altresco to projected market costs and hearings are currently ongoing. In a separate but related matter, we appealed the Massachusetts Energy Facilities Siting Board's (EFSB) approval of construction of Altresco's proposed generating station based partly on the EFSB's failure to consider market information and forecasts.

We also currently remain subject to the DPU's 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. As a result of our 1994 IRM filing, the DPU found that we did not have a need for additional generating capacity through 2001 and therefore were not required to issue a competitive request for proposals for new generating capacity. Required updates to our IRM filing have been postponed due to the current industry restructuring proceedings ongoing at the DPU.

Nonutility business

We have an unregulated subsidiary, Boston Energy Technology Group (BETG), in which we have authority from the DPU to invest up to $45 million. This wholly owned subsidiary engages primarily in energy conservation services and the production of water treatment systems. In 1996 BETG entered into a joint venture to build a series of ice-based cooling systems as an alternative to costly chemical systems. BETG's investment in this joint venture, Northwind Boston, is 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 approximately 40 properties where oil or hazardous materials were previously spilled or released. 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 approximately 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, 1995, 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 that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

Uncertainties continue to exist with respect to the disposal of both spent nuclear fuel and low-level radioactive waste (LLW) resulting from the operation of Pilgrim Station. 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. In 1995 we regained access to the LLW disposal facility located in Barnwell, South Carolina. Refer to Note E to the Consolidated Financial Statements for further discussion regarding spent nuclear fuel and LLW disposal.

As part of a 1991 DEP consent order, we are currently required to fuel New Boston Station exclusively by natural gas, except in certain emergency circumstances. The station has the ability to burn natural gas, oil or both. We have arrangements for a firm supply of natural gas to run the station at a minimum level and are developing a least-cost plan for operating beyond this minimum level which principally utilizes interruptible gas supplies or short-term capacity purchases.

The 1990 Clean Air Act Amendments 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 allowances 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 low nitrogen oxides burners at New Boston, have

allowed 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 or years thereafter. The extent of any additional emission restrictions and the cost of any further modifications is uncertain at this time.

Public concern continues 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. We have also been named as a party in a lawsuit by Subaru of New England, Inc. and Subaru Distributors Corporation. The plaintiffs are claiming certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from New Boston Station. We believe that we have a strong defense in this case. We are also involved in certain other legal matters. We are unable to fully determine a range of reasonably possible litigation costs in excess of amounts previously accrued, although based on the information currently available, we do not expect that any such additional costs will have a material impact on our financial condition. However, additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

New accounting pronouncement

Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of, is effective in 1996. This statement establishes accounting standards for recognizing and measuring asset impairment losses. Refer to Note M to the Consolidated Financial Statements for more information regarding this statement and its potential effects.

Safe harbor cautionary statement

We occasionally make forward-looking statements such as forecasts and projections of expected future performance or statements of our plans and objectives. These forward-looking statements may be contained in filings with the Securities and Exchange Commission, press releases and oral statements. Actual results could potentially differ materially from these statements. Therefore, no assurances can be given that the outcomes stated in such forward-looking statements and estimates will be achieved.

The above sections include certain forward-looking statements about the effects of the industry restructuring process and our related plan, operating results, Pilgrim Station's performance and environmental and legal issues.

The effects of the industry restructuring process currently underway at the DPU and our related plan could differ from our expectations. This could occur as regulatory decisions and negotiated settlements between utilities and intervenors are finalized during the restructuring process. In addition, the development of a competitive electric generation market and the impacts of actual electric supply and demand in New England may affect the ultimate results of the industry restructuring and our plan.

The impacts of our continued cost control procedures on our operating results could differ from our expectations. The effects of changes in economic conditions, tax rates, interest rates, technology and the prices and availability of operating supplies could materially affect our projected operating results.

Pilgrim Station's performance could differ from our expectations. The station's capacity factor could be impacted by changes in regulations or by unplanned outages resulting from certain operating conditions.

The impacts of various environmental and legal issues could differ from our expectations. New regulations or changes to existing regulations could impose additional operating requirements or liabilities. The effects of changes in specific hazardous waste site conditions and cleanup technology could affect our estimated cleanup liabilities. The impacts of changes in available information and circumstances regarding legal issues could affect our estimated litigation costs.

Item 8. Financial Statements and Supplementary Financial Information

Consolidated Statements of Income

(in thousands, except earnings per share)	years ended December 31, 1995	1994	1993
Operating revenues	$1,628,503	$1,544,735	$1,482,159
Operating expenses:			
Fuel	170,337	156,951	170,799
Purchased power	365,469	356,874	370,049
Other operations and maintenance	439,263	435,824	405,609
Restructuring costs	34,000	0	0
Depreciation and amortization	153,339	148,845	137,710
Amortization of deferred cost of cancelled nuclear unit	0	19,791	0
Amortization of deferred nuclear outage costs	18,933	7,721	6,546
Demand side management programs	45,125	35,438	37,504
Taxes - property and other	106,361	100,015	93,102
Income taxes	68,276	54,798	35,143
Total operating expenses	1,401,103	1,316,257	1,256,462
Operating income	227,400	228,478	225,697
Other income (expense), net	(575)	3,979	211
Operating and other income	226,825	232,457	225,908
Interest charges:			
Long-term debt	106,640	102,570	104,375
Other	12,642	12,343	9,778
Allowance for borrowed funds used during construction	(4,767)	(7,478)	(5,463)
Total interest charges	114,515	107,435	107,690
Net income	112,310	125,022	118,218
Preferred dividends provided	15,571	15,765	15,705
Balance available for common stock	$ 96,739	$ 109,257	$ 102,513
Weighted average common shares outstanding	46,592	45,338	44,959
Earnings per share of common stock	$ 2.08	$ 2.41	$ 2.28

Consolidated Statements of Retained Earnings

(in thousands)	years ended December 31, 1995	1994	1993
Balance at beginning of year	$ 247,004	$ 218,292	$ 192,948
Net income	112,310	125,022	118,218
Subtotal	359,314	343,314	311,166
Cash dividends declared:			
Preferred stock	15,571	15,765	15,705
Common stock	86,399	80,545	77,169
Subtotal	101,970	96,310	92,874
Balance at end of year	$ 257,344	$ 247,004	$ 218,292

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

Consolidated Balance Sheets

(in thousands)		1995		December 31, 1994
Assets				
Utility plant in service, at original cost	$4,315,422		$4,074,810	
Less: accumulated depreciation	1,439,996	$2,875,426	1,344,452	$2,730,358
Nuclear fuel	302,594		291,836	
Less: accumulated amortization	251,951	50,643	236,239	55,597
Construction work in progress		29,573		144,048
Net utility plant		2,955,642		2,930,003
Investments in electric companies, at equity		23,620		24,678
Nuclear decommissioning trust		102,894		82,831
Current assets:				
Cash and cash equivalents	5,841		6,822	
Accounts receivable	219,114		189,361	
Accrued unbilled revenues	37,113		32,240	
Fuel, materials and supplies, at average cost	59,631		71,560	
Prepaid expenses and other	23,607	345,306	26,693	326,676
Deferred debits:				
Regulatory assets	156,774		198,148	
Intangible asset - pension	27,386		22,849	
Other	32,227	216,387	31,391	252,388
Total assets		$3,643,849		$3,616,576
Capitalization and Liabilities				
Common stock equity		$ 989,438		$ 915,747
Cumulative preferred stock:				
Nonmandatory redeemable series		123,000		123,000
Mandatory redeemable series		92,000		94,000
Long-term debt		1,160,223		1,136,617
Current liabilities:				
Long-term debt/preferred stock due within one year	$ 102,667		$ 102,250	
Notes payable	126,441		214,786	
Accounts payable	133,474		130,496	
Accrued interest	25,113		24,464	
Dividends payable	25,351		23,533	
Pension benefits	32,602		31,908	
Other	105,442	551,090	85,204	612,641
Deferred credits:				
Power contracts	21,396		40,277	
Accumulated deferred income taxes	497,282		515,454	
Accumulated deferred investment tax credits	62,970		67,048	
Nuclear decommissioning reserve	113,288		92,404	
Other	33,162	728,098	19,388	734,571
Commitments and contingencies		-		-
Total capitalization and liabilities		$3,643,849		$3,616,576

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

Consolidated Statements of Cash Flows

(in thousands)	years ended December 31, 1995	1994	1993
Operating activities:			
Net income	$112,310	$125,022	$118,218
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	148,630	142,932	130,074
Amortization of nuclear fuel	19,029	18,810	21,816
Amortization of deferred cost of cancelled nuclear unit, net	0	19,067	0
Amortization of deferred nucl' r outage costs	18,933	7,721	6,546
Other amortization	15,702	14,692	10,158
Deferred income taxes	(21,115)	(4,184)	10,303
Investment tax credits	(4,078)	(4,092)	(4,073)
Allowance for borrowed funds used during construction	(4,767)	(7,478)	(6,463)
Net changes in:			
Accounts receivable and accrued unbilled revenues	(34,626)	(20,701)	13,206
Fuel, materials and supplies	7,202	3,093	9,722
Accounts payable	2,978	23,196	(18,916)
Other current assets and liabilities	26,485	35,217	25,660
Other, net	23,975	14,847	(20,437)
Net cash provided by operating activities	310,658	368,142	295,814
Investing activities:			
Plant expenditures (excluding AFUDC)	(180,822)	(198,771)	(246,774)
Nuclear fuel expenditures	(13,621)	(21,934)	(6,491)
Capitalized demand side management expenditures	0	(37,007)	(37,156)
Sale of plant assets, net	3,018	15,972	0
Nuclear c commissioning trust investments	(20,063)	(16,771)	(15,189)
Electric company investments	1,058	(386)	1,106
Net cash used by investing activities	(210,430)	(258,897)	(304,504)
Financing activities:			
Issuances:			
Common stock	64,888	10,634	10,855
Preferred stock	0	0	40,000
Long-term debt	125,000	15,000	815,000
Redemptions:			
Preferred stock	(2,000)	(2,000)	(40,000)
Long-term debt	(100,600)	(50,000)	(648,625)
Net change in notes payable	(88,345)	10,635	(71,349)
Dividends paid	(100,152)	(95,460)	(92,370)
Net cash provided (used) by financing activities	(101,209)	(111,191)	13,511
Net increase (decrease) in cash and cash equivalents	(981)	(1,946)	4,821
Cash and cash equivalents at the beginning of the year	6,822	8,768	3,947
Cash and cash equivalents at the end of the year	$ 5,841	$ 6,822	$ 8,768
Cash paid during the year for:			
Interest, net of amounts capitalized	$113,945	$108,462	$103,720
Income taxes	$ 96,180	$ 46,074	$ 30,305

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

Notes to Consolidated Financial Statements

Note A. Nature of Operations

We are an investor-owned regulated public utility operating in the energy and energy services business. This includes the generation, purchase, transmission, distribution and sale of electric energy and the development and implementation of electric demand side management programs. A portion of our generation is produced by a nuclear unit, Pilgrim Station. We supply electricity at retail to an area of 590 square miles, including the City of Boston and 39 surrounding cities and towns. We also supply electricity at wholesale for resale to other utilities and municipal electric departments. Electric operating revenues were 89% retail and 11% wholesale in 1995.

Note B. 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. Certain prior period amounts on the financial statements were reclassified to conform with the current presentation.

We follow accounting policies prescribed by our federal and state regulators, the Federal Energy Regulatory Commission (FERC) and the Massachusetts Department of Public Utilities (DPU). We are also subject to the accounting and reporting requirements of the Securities and Exchange Commission. The financial statements conform with generally accepted accounting principles (GAAP). As a rate-regulated company we are subject to Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71), under GAAP. The application of SFAS 71 results in differences in the timing of recognition of certain expenses from that of other businesses and industries. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

*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 1995, 1994 and 1993 at composite rates of 3.10%, 3.11% and 3.09% per year, respectively, based on estimated useful lives of the various classes of property. The cost of decommissioning Pilgrim Station is excluded from these 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 defer the incremental costs associated with nuclear refueling outages and amortize them over future periods. In 1995 we changed the amortization period to two years from five years. The two-year amortization period is consistent with the two-year cycle between nuclear refueling outages at Pilgrim Station. The change from the prior five-year amortization period approved in the 1992 settlement agreement was made following the DPU's August 1995 order on electric industry restructuring, which is discussed further in the Outlook for the Future section of Management's Discussion and Analysis. This order requires utilities to mitigate potentially strandable costs by available and reasonable means. The prior regulatory treatment of recovery over a five year period resulted in a significant lag between the expenditure and recovery of outage costs. We decided not to request recovery of the buildup of costs resulting from this regulatory lag. Accordingly, the remaining $9 million of deferred costs allocable to retail customers for refueling outages performed in 1991 and 1993 was written off. Approximately $15 million of deferred costs from the 1995 refueling outage is being amortized over two years.

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

We expense discounts, 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 1995, 1994 and 1993 were 6.35%, 4.45% and 3.62%, 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 when purchased. Outstanding checks are included in cash and accounts payable until 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 are expected to be collected from customers through future charges in accordance with agreements with the DPU. These costs are to be expensed when the corresponding revenues are received in order to appropriately match revenues and expenses. The majority of these costs is currently being recovered from customers over varying time periods. No return on investment was earned on the regulatory assets.

Regulatory assets consisted of the following:

		December 31,
	1995	1994
Redemption premiums	$ 44,709	$52,859
Income taxes, net	46,121	44,745
Power contracts	21,396	40,277
Pension and postretirement costs	13,811	22,761
Nuclear outage costs	13,471	17,804
Other	17,266	19,702
	$156,774	$198,148

Note C. Rate Regulation

In 1992 the DPU approved a three-year settlement agreement relating to our rate case proceedings. The agreement 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 through 1995.

In February 1996 we filed an industry restructuring plan with the DPU in response to its August 1995 order on restructuring the electric utility industry. This plan is expected to lead to negotiations with intervening parties that will result in new rates and performance incentives to be implemented in a new industry structure with a competitive generation market and incentive-regulated transmission and distribution systems. Refer to Management's Discussion and Analysis for further information regarding the restructuring of the electric utility industry in Massachusetts and our proposed plan. State regulatory proceedings do not affect our contract or wholesale power rates, which are regulated by the FERC.

Note D. Income Taxes

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109), which 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 $46.1 million and $44.7 million and corresponding net increases in accumulated deferred income taxes as of December 31, 1995, and December 31, 1994, 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:

(in thousands)	December 31, 1995	1994
Deferred tax liabilities:		
Plant-related	$521,280	$511,572
Other	95,148	105,786
	616,428	617,358
Deferred tax assets:		
Plant-related	12,590	13,216
Investment tax credits	40,632	43,273
Alternative minimum tax	0	1,332
Other	65,924	44,083
	119,146	101,904
Net accumulated deferred income taxes	$497,282	$515,454

No valuation allowances for deferred tax assets are deemed necessary.

Components of income tax expense were as follows:

(in thousands)	years ended December 31, 1995	1994	1993
Current income tax expense	$93,469	$63,358	$28,913
Deferred tax expense	(21,115)	(4,468)	10,303
Investment tax credits	(4,078)	(4,092)	(4,073)
Income taxes charged to operations	68,276	54,798	35,143
Taxes on other income:			
Current	(1,729)	2,550	1,205
Deferred	0	284	0
	(1,729)	2,834	1,205
Total income tax expense	$66,547	$57,632	$36,348

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:

	1995	1994	1993
Statutory tax rate	35.0%	35.0%	35.0%
State income tax, net of federal income tax benefit	4.3	4.3	4.2
Investment tax credits	(2.3)	(2.3)	(2.6)
Municipal property tax adjustment	-	-	(0.6)
Reversal of deferred taxes - settlement agreement	-	(5.5)	(13.0)
Other	0.1	(0.1)	0.4
Effective tax rate	37.1%	31.4%	23.4%

Note E. 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 currently expensing an estimate of the decommissioning costs over Pilgrim's expected service life. The 1995 expense of approximately $14 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 that 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 which 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 in order to evaluate the potential impact of long-term spent fuel storage options resulting from delays in the United States Department of Energy (DOE) spent fuel removal program. (See part 2 below for a discussion of spent fuel removal.) The partial update indicates an estimated decommissioning cost of $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 February 1996 the Financial Accounting Standards Board (FASB) issued proposed new rules for accounting for liabilities related to closure and removal of long-lived assets, which includes decommissioning. If these draft rules are adopted we would be required to retroactively recognize the entire estimated liability for decommissioning costs on the balance sheet, offset by an addition to nuclear plant. The plant addition would be depreciated over Pilgrim's expected service life. The liability would be measured based on the present value of estimated future cash flows. The cumulative effect of adoption of these proposed rules could result in a regulatory asset to be recovered from customers to the extent that the present value difference in the liability between when the liability was incurred and when the rules are adopted exceeds the depreciation expense previously recognized for decommissioning. If it is not probable that we could recover these costs from customers, we would have to charge the cumulative effect of the difference to income instead of recording a regulatory asset. In addition, trust fund earnings would be reported on the income statement.

2. Spent Nuclear Fuel

The spent fuel storage facility at Pilgrim Station provides storage capacity through approximately 2003. We have a license amendment from the Nuclear Regulatory Commission to modify the facility to provide sufficient room for spent nuclear fuel generated through the end of Pilgrim's operating license in 2012; however, any further modifications are subject to review by the DPU. 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 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 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

We regained access to low-level radioactive waste (LLW) disposal facilities located in Barnwell, South Carolina, in 1995. This site is currently the only disposal facility available to us. 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. 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 F. Corporate Restructuring

In 1995 we streamlined the corporate organization and reorganized the company into separate business units in order to strengthen our competitiveness in the changing electric energy market. In conjunction with this reorganization we offered enhanced retirement programs and implemented a special severance program to reduce employee staffing levels. Under the enhanced retirement programs 330 employees elected to retire, and 149 employees whose positions were eliminated became eligible for benefits under the special severance program. These programs resulted in a $34 million pre-tax charge ($20.7 million net of tax) over the third and fourth quarters of 1995. The charge consisted of $24 million for the retirement programs and $10 million for the severance program.

The enhanced retirement programs were offered to all employees at least 55 years old, with different years of service requirements for management and union employees. The programs provided for supplemental salary payments and waivers of the early retirement pension reduction and the medical and life insurance benefits years of service requirement. The special severance program was provided for all employees whose positions were eliminated in the reorganization, who were all management and administrative support personnel. Severance benefits provided were salary payments, medical insurance and outplacement services. The retirement programs' pension and medical and life insurance benefits, totalling $16 million, will be paid from pension and employee benefit trusts. The liabilities to the trusts are included on the consolidated balance sheet at December 31, 1995, in pension benefits and other current liabilities. All other benefits are being paid from general corporate funds. As of December 31, 1995, $10 million had been paid and $8 million remained in other current liabilities.

Note G. Pensions and Other Postretirement 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 highest eligible average compensation during the last ten years of credited 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. The retirement plan assets consist of equities, bonds, money market funds, insurance contracts and real estate funds.

We also have a supplemental pension plan for certain management employees. Benefits under this plan are based on final compensation upon retirement. The plan is not funded. The plan's cost and benefit obligation amounts are included in the following pension information for 1995. Amounts related to the plan prior to 1995 were not material to our total pension costs and obligations.

Net pension cost consisted of the following components:

(in thousands)	years ended December 31, 1995	1994	1993
Current service cost - benefits earned	$11,339	$15,057	$ 11,734
Interest cost on projected benefit obligation	31,789	33,961	33,181
Actual net loss/(return) on plan assets	(72,192)	214	(44,470)
Net amortization and deferral	49,557	(32,169)	8,528
Net pension cost (a)	$20,493	$17,063	$ 8,973

(a) In accordance with our 1992 settlement agreement we deferred the difference in the net pension cost of the retirement plan and its annual funding amount. Net deferred costs amounted to ($1.2) million and $6.5 million at December 31, 1995 and 1994, respectively. Total net pension costs recorded as expense in 1995, 1994 and 1993 were $28 million, $25 million and $5 million, respectively.

We used the following assumptions for calculating pension cost:

	1995	1994	1993
Discount rate	8.25%	7.00%	8.25%
Expected long-term rate of return on assets	10.00%	10.00%	10.00%
Compensation increase rate	3.90%	4.50%	4.50%

The pension plans' funded status was as follows:

(in thousands)	December 31, 1995	1994
Actuarial present value of benefit obligations:		
Accumulated benefit obligation, including vested benefits of $386,020 and $305,632 (b)	$401,329	$321,072
Plan assets at fair value	$358,572	$289,164
Projected obligation for service rendered to date	(487,702)	(387,910)
Projected benefit obligation in excess of plan assets	(129,130)	(98,746)
Unrecognized prior service cost	22,506	13,328
Unrecognized net loss	83,187	67,361
Unrecognized net obligation	8,064	8,998
Minimum liability adjustment (c)	(27,386)	(22,849)
Net pension liability (d)	$(42,759)	$(31,908)

(b) The accumulated benefit obligation at December 31, 1995, includes $13.5 million related to the enhanced retirement programs offered in 1995 as discussed in Note F.

(c) 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 additional minimum liabilities and corresponding intangible assets of $27 million and $23 million on our consolidated balance sheets at December 31, 1995 and 1994, respectively.

(d) Net pension liability included on the consolidated balance sheets in current liabilities is $33 million and $32 million, and in deferred credits is $10 million and $0 at December 31, 1995 and 1994, respectively.

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

	1995	1994
Discount rate	7.25%	8.25%
Compensation increase rate	3.90%	3.90%

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 $9 million in 1995, $8 million in 1994 and $7 million in 1993.

2. Other Postretirement Benefits

In addition to pension benefits, we also provide health care and other benefits to our retired employees who meet certain age and years of service eligibility requirements. These postretirement benefits other than pensions (PBOPs) are accounted for in accordance with Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). Our 1992 settlement agreement provides us with a five-year expense phase-in of the PBOP costs incurred under SFAS 106 and allows us to defer any 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 benefits costs to external trusts. Accordingly, we recorded expenses of $23 million in 1995, $17 million in 1994 and $15 million in 1993, reflecting the amount of current cost recovery from customers. Net deferred costs amounted to $15 million and $16 million at December 31, 1995 and 1994, respectively.

Net postretirement benefits cost consisted of the following components:

	years ended December 31,		
(in thousands)	1995	1994	1993
Current service cost - benefits earned	$ 3,408	$ 4,978	$ 4,351
Interest cost on accumulated benefit obligation	13,521	13,632	14,286
Actual return on plan assets	(7,151)	(187)	0
Amortization of transition obligation	9,151	9,151	9,151
Net amortization and deferral	3,017	(2,581)	0
Net postretirement benefits cost	$21,946	$24,993	$27,788

We used the following assumptions for calculating postretirement benefits cost:

	1995	1994	1993
Discount rate	8.25%	7.00%	8.00%
Expected long-term rate of return on assets	9.00%	9.00%	9.00%
Health care cost trend rate	7.00%	9.00%	12.50%

The health care cost trend rate is assumed to decrease by one percent in 1996 and 1997 and to remain at 5% in 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 8% and would increase the accumulated benefit obligation at December 31, 1995, by 7.5%.

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

			December 31,	
(in thousands)		1995		1994
Trust assets at fair value		$ 51,064		$ 33,300
Accumulated obligation for service rendered to date from:				
Retirees	$(110,877)		$(93,960)	
Active employees eligible to retire	(31,980)		(31,159)	
Active employees not eligible to retire	(53,514)	(196,371)	(51,545)	(176,664)
Accumulated benefit obligation in excess of trust assets		(145,307)		(143,364)
Unrecognized prior service cost		(17,889)		(19,502)
Unrecognized net (gain)/loss		5,612		(1,849)
Unrecognized transition obligation		155,564		164,715
Net postretirement benefits liability		$ (2,020)		$ 0

The net postretirement benefits liability at December 31, 1995, represents the additional PBOP obligation from the enhanced retirement programs offered in 1995 (see Note F). This additional amount was not funded as part of the 1995 PBOP cost.

The weighted average discount rates used to measure the accumulated benefit obligation were 7.25% in 1995 and 8.25% in 1994. The trust assets consist of equities, bonds and money market funds.

Note H. 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 I. Cancelled Nuclear Unit

In 1982 we began expensing the cost of our cancelled Pilgrim 2 nuclear unit over approximately eleven and one-half years in accordance with an order received from the DPU. 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 1992 settlement agreement.

Note J. Capital Stock

(dollars in thousands, except per share amounts)			1995	December 31, 1994	1993
Common stock equity:					
Common stock, par value $1 per share, 100,000,000 shares authorized; 48,003,178, 45,535,477 and 45,129,227 shares issued and outstanding:			$ 48,003	$ 45,535	$ 45,129
Premium on common stock			683,686	622,803	612,653
Retained earnings			257,344	247,004	218,292
Surplus invested in plant			405	405	405
Total common stock equity			$989,438	$915,747	$876,479
Cumulative preferred stock:					
Par value $100 per share, 2,890,000 shares authorized; issued and outstanding:					
Nonmandatory 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	40,000
8.25%	400,000	-	40,000	40,000	40,000
Total nonmandatory redeemable series			$123,000	$123,000	$123,000
Mandatory redeemable series:					
Series	Current Shares Outstanding	Redemption Price/Share			
7.27%	440,000	$103.390	$ 44,000	$ 46,000	$ 48,000
8.00%	500,000	-	50,000	50,000	50,000
Total mandatory redeemable series			94,000	96,000	98,000
Less: due within one year			2,000	2,000	2,000
Total mandatory redeemable series, net			$ 92,000	$ 94,000	$ 96,000

Dividends Declared per Share

	1995	1994	1993
Common stock	$ 1.835	$ 1.775	$ 1.715
Preferred stock:			
4.25% series	$ 4.250	$ 4.250	$ 4.253
4.78% series	4.780	4.780	4.785
7.27% series	7.270	7.270	7.270
7.75% series	7.750	7.750	5.707
8.00% series	8.000	8.000	8.000
8.25% series	8.250	8.250	8.250
8.88% series	0	0	2.220

1. *Common Stock*

Common stock issuances in 1993 through 1995 were as follows:

(in thousands)	Number of Shares	Total Par Value	Premium on Common Stock
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	406	406	10,150
Balance December 31, 1994	45,535	45,535	622,803
Dividend reinvestment plan (a)	468	468	11,404
New issuances (b)	2,000	2,000	49,479
Balance December 31, 1995	48,003	$48,003	$683,686

(a) At December 31, 1995, the remaining authorized common shares reserved for future issuance under the Dividend Reinvestment and Common Stock Purchase Plan were 1,941,219 shares.

(b) We used the net proceeds of the 1995 common stock issuances to reduce short-term debt.

2. *Cumulative Nonmandatory Redeemable Preferred Stock*

In 1993 we issued 400,000 shares of 7.75% cumulative nonmandatory 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 nonmandatory redeemable preferred stock.

3. *Cumulative Mandatory Redeemable Preferred Stock*

The 440,000 shares of 7.27% sinking fund series cumulative preferred stock are currently redeemable at our option at $103.390. 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 noncumulative 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 the 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.

Note K. Indebtedness

(in thousands)	December 31, 1995	1994
Long-term debt:		
Debentures:		
8.875%, due December 1995	$ 0	$ 100,000
5.125%, due March 1996	100,000	100,000
5.700%, due March 1997	100,000	100,000
5.950%, due March 1998	100,000	100,000
6.800%, due February 2000	65,000	65,000
6.050%, due August 2000	100,000	100,000
6.800%, due March 2003	150,000	150,000
7.800%, due May 2010	125,000	0
9.875%, due June 2020	100,000	100,000
9.375%, due August 2021	115,000	115,000
8.250%, due September 2022	60,000	60,000
7.800%, due March 2023	200,000	200,000
Total debentures	1,215,000	1,190,000
Less: due within one year	100,000	100,000
Net long-term debentures	1,115,000	1,090,000
Sewage facility revenue bonds	35,700	36,300
Less: due within one year	1,600	600
Less: funds held by trustee	3,877	4,083
Net long-term sewage facility revenue bonds	30,223	31,617
Massachusetts Industrial Finance Agency bonds:		
5.750%, due February 2014	15,000	15,000
Total long-term debt	$1,160,223	$1,136,617
Short-term debt:		
Notes payable:		
Bank loans	$ 75,941	$ 80,786
Commercial paper	50,500	134,000
Total notes payable	$ 126,441	$ 214,786

1. Long-Term Debt

In 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.

In 1994 we redeemed at par the $25 million of variable rate Series S first mortgage bonds. 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.

In May 1995 we issued $125 million of 7.80% debentures due in 2010. We used the net proceeds from this issuance to reduce short-term debt.

The 9 7/8% debentures due 2020 are first redeemable in June 2000 at a redemption price of 104.483%, the 9 3/8% series due 2021 are first redeemable

in August 2001 at 104.612%, the 8.25% series due 2022 are first redeemable in September 2002 at 103.780% and the 7.80% series due 2023 are first redeemable in March 2003 at 103.730%. No other series are redeemable prior to maturity. There is no sinking fund requirement for any series of our debentures.

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 through 2015. In May 1995 $0.6 million was redeemed as scheduled. 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 for extraordinary expenses, we would be required to make additional capital contributions or loans to the subsidiary up to a maximum of $1 million.

The aggregate principal amounts of our long-term debt (including HEEC sinking fund requirements) due through 2000 are $101.6 million per year in 1996 through 1998, $1.6 million in 1999 and $166.6 million in 2000.

*2. **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:

(dollars in thousands)	1995	1994	1993
Maximum short-term borrowings	$327,769	$268,100	$320,000
Weighted average amount outstanding	$165,720	$214,640	$220,149
Weighted average interest rates excluding commitment fees	6.2%	4.5%	3.4%

Note L. 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 $102.9 million approximates fair value based on quoted market prices of securities held.

Cash and cash equivalents:
The carrying amount of $5.8 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, 1995, are as follows:

(in thousands)	Carrying Amount	Fair Value
Mandatory redeemable cumulative preferred stock	$ 94,000	$ 98,005
Sewage facility revenue bonds	35,700	38,446
Unsecured debt	1,230,000	1,276,213

Note M. New Accounting Pronouncement

In 1995 the FASB issued Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of (SFAS 121), effective in 1996. This statement clarifies when and how to recognize asset impairments. In addition, SFAS 121 requires that all regulatory assets, which must have a high probability of recovery to be initially established, continue to meet that high probability standard or be written off. However, if written off, a regulatory asset can be restored if it regains a high probability of recovery. The impact of this standard on our plant and regulatory assets will be determined by regulatory changes implemented by the DPU and FERC. Based on the transition principles of the DPU's order on industry restructuring and our related plan, which are discussed in the Outlook for the Future section of Management's Discussion and Analysis, we do not expect SFAS 121 to have an adverse impact on our financial position or results of operations in the near term. Our conclusion may change as the actual shape of restructuring of the industry in Massachusetts develops. If recovery of our plant and regulatory assets is not provided, SFAS 121 could require a write-down of these assets.

Note N. Commitments and Contingencies

1. Contractual Commitments

At December 31, 1995, we had estimated contractual obligations for plant and equipment of approximately $35 million.

We have leases for certain facilities and equipment. Our estimated minimum rental commitments under both transmission agreements and noncancellable leases for the years after 1995 are as follows:

(in thousands)	
1996	$ 24,908
1997	22,109
1998	19,002
1999	17,408
2000	16,656
Years thereafter	108,417
Total	$208,500

We will capitalize a portion of these lease rentals as part of plant expenditures in the future. The total expense for both lease rentals and transmission agreements was $24.5 million in 1995, $28.6 million in 1994 and $29.8 million in 1993, net of capitalized expenses of $2.7 million in 1995, $2.4 million in 1994 and $5.2 million in 1993.

We also have various outstanding commitments for take or pay and throughput agreements, primarily to supply New Boston Station with natural gas. The fixed and determinable portions of the obligations are $16.1 million in 1996, 1997 and 1998, $24.8 million in 1999 and $13.8 million in 2000. We are also committed to purchase natural gas at market prices. The total expense under these agreements was $13.9 million in 1995, and $6.5 million in 1994 and 1993.

2. 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 on 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, 1995, our portion of these guarantees was approximately $19 million.

3. Yankee Atomic Electric Company

We have a 9.5% stock investment of approximately $2 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.

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 $21 million as of December 31, 1995. 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.

4. 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 $15 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 additional 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 any such assessment.

5. *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. We have also been named as a party in a lawsuit by Subaru of New England, Inc. and Subaru Distributors Corporation. The plaintiffs are claiming certain automobiles stored on lots in South Boston suffered pitting damage caused by emissions from New Boston Station. We believe that we have a strong defense in this case. We are also involved in certain other legal matters. We are unable to fully determine a range of reasonably possible litigation costs in excess of amounts previously accrued, although based on the information currently available, we do not expect that any such additional costs will have a material impact on our financial condition. However, additional litigation costs that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

6. *Hazardous Waste*

We own or operate approximately 40 properties where oil or hazardous materials were previously spilled or released. 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 approximately 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, 1995, 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 that may result from a change in estimates could have a material impact on the results of a reporting period in the near term.

Note O. 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 on our consolidated income statements. Information relating to these contracts as of December 31, 1995, is as follows:

				proportionate share (in thousands)		
		Units of Capacity Purchased[a]		1995 Minimum Debt	1995 Interest Portion of Minimum	Debt Outstanding Through Cont.
Generating Unit	Contract Expiration Date	%	MW	Service	Debt Service	Exp. Date
Canal Unit 1	2001	25.0	139	$ 1,122	$ 349	$ 3,400
Mass. Bay Transportation Authority - 1	2005	100.0	34	(b)	(b)	(b)
Connecticut Yankee Atomic	2007	9.5	55	2,646	1,786	13,857
Ocean State Power - Unit 1	2010	23.5	67	4,819	3,318	20,749
Ocean State Power - Unit 2	2011	23.5	66	4,090	3,049	17,228
Northeast Energy Associates	(c)	(c)	219	(c)	(c)	(c)
L'Energia	2013	73.0	64	(d)	(d)	(d)
MassPower (e)	2013	44.3	117	12,217	7,662	81,983
Mass. Bay Transportation Authority - 2	2019	100.0	34	(f)	(f)	(f)
Total			795	$24,894	$16,164	$137,217

(a) The Northeast Energy Associates contract represents 5.9% of our total system generation capability. The remaining units listed above represent 15.6% 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 1995 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 1995 were approximately $127 million.

(d) We pay for this energy based on a price per kWh actually received. The total charges under this contract for 1995 were approximately $25 million.

(e) Payments for this contract 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 1995 were approximately $49 million.

(f) The second Massachusetts Bay Transportation Authority contract started in June 1995. Capacity payments under this contract do not begin until 2003. At that time we will be required to pay $84.57 per kilowatt-year times the qualified capacity plus incremental operating maintenance and fuel costs.

Our total fixed and variable costs for these contracts in 1995, 1994 and 1993 were approximately $283 million, $286 million and $225 million, respectively. Our minimum fixed payments under these contracts for the years after 1995 are as follows:

(in thousands)	
1996	$ 106,649
1997	103,682
1998	105,778
1999	105,258
2000	103,676
Years thereafter	1,187,672
Total	$1,712,715
Total present value	$ 883,409

2. *Long-Term Power Sales*

In addition to wholesale power sales, 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[a]
1995					
First quarter	$379,678	$ 47,610	$20,202	$16,300	$0.36
Second quarter	380,828	55,683	26,137	22,247	0.48
Third quarter	498,554	102,695[b]	72,368[b]	68,478[b]	1.46[b]
Fourth quarter	369,443	21,412[b]	(6,397)[b]	(10,286)[b]	(0.21)[b]
1994					
First quarter	$376,935	$ 45,891	$19,812	$15,850	$0.35
Second quarter	368,245	50,812	23,982	20,031	0.44
Third quarter	448,179	96,880	70,182	66,256	1.46
Fourth quarter	351,376	34,895	11,046	7,120	0.16

(a) Based on the weighted average number of common shares outstanding during the quarter.

(b) As discussed in Note F to the Consolidated Financial Statements, we incurred a $34 million pre-tax charge related to our corporate restructuring over the third and fourth quarters of 1995. Amounts excluding the restructuring charge are as follows:

	Operating Income	Net Income	Balance Available for Common Stock	Earnings Per Average Common Share
Third quarter	$107,779	$77,452	$73,562	$1.57
Fourth quarter	36,991	9,182	5,293	0.11

Certain reclassifications were made to the data reported in prior periods to conform with the current method of presentation.

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 28, 1996, 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.

(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 28, 1996, 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 6 through 12 of the definitive proxy statement dated March 28, 1996, 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 page 5 of the definitive proxy statement dated March 28, 1996, 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

(a) The following documents are filed as part of this Form 10-K:

No financial statement schedules are prepared 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	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
4.1.3	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

		Exhibit	SEC Docket
4.1.4	Revolving Credit Agreement dated February 12, 1993	4.1.24	1-2301 Form 10-K for the year ended December 31, 1992
4.1.5	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
4.1.6	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
4.1.7	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
4.1.8	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

Filed herewith:

4.1.9	Votes of the Pricing Committee of the Board of Directors of Boston Edison Company taken May 10, 1995 re 7.80% debentures due May 15, 2010		

		Exhibit	SEC Docket
4.1.10	First Amendment to Revolving Credit Agreement		

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 10 Material Contracts

Incorporated herein by reference:

		Exhibit	SEC Docket
10.1	Key Executive Benefit Plan Standard Form of Agreement, May 1986	10.1	1-2301 Form 10-Q for the quarter ended June 30, 1986
10.1.1	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
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

		Exhibit	SEC Docket
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
10.5.1	Amendment No. 1 to Deferred Compensation Trust dated March 31, 1994	10.5.1	1-2301 Form 10-K for the year ended December 31, 1994
10.6	Directors Retirement Benefit (1993 Plan)	10.8.1	1-2301 Form 10-K for the year ended December 31, 1993
10.7	Description of Supplemental Fee Arrangement for Certain Directors	10.7	1-2301 Form 10-K for the year ended December 31, 1994
10.8	Performance Share Plan, Amendment and Restatement dated October 24, 1994	10.8	1-2301 Form 10-K for the year ended December 31, 1994
10.9	Boston Edison Company Deferred Compensation Plan, Amendment and Restatement dated January 31, 1995	10.9	1-2301 Form 10-K for the year ended December 31, 1994
10.10	Employment Agreement applicable to Ronald A. Ledgett dated April 30, 1987	10.10	1-2301 Form 10-K for the year ended December 31, 1994

Exhibit SEC Docket

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, 1995

12.2 Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividend Requirements for the Year Ended December 31, 1995

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.

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	SEC Docket

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), May 31, 1995 (File No. 33-59693) 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), March 17, 1993 (33-59662 and 33-59682) and April 6, 1995 (33-58457)

Exhibit 27 Financial Data Schedule

Filed herewith:

27.1 Schedule UT

Exhibit 99 Additional Exhibits

Incorporated herein by reference:

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

		Exhibit	SEC Docket
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, 1994, 1993 and 1992		1-2301 Form 10-K/A Amendments to Form 10-K for the years ended December 31, 1994 and 1993 and Form 8 Amendment to Form 10-K for the year ended December 31, 1992 dated June 29, 1995, June 30, 1994 and June 29, 1993, 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 1995.

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/ James J. Judge
James J. Judge
Senior Vice President and Treasurer
(Principal Financial Officer)

Date: March 28, 1996

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 28th day of March 1996.

/s/ Thomas J. May Thomas J. May	Chairman of the Board, President and Chief Executive Officer
/s/ Robert J. Weafer, Jr. Robert J. Weafer, Jr.	Vice President - Finance, Controller and Chief Accounting Officer
/s/ William F. Connell William F. Connell	Director
/s/ Gary L. Countryman Gary L. Countryman	Director
/s/ Thomas G. Dignan, Jr. Thomas G. Dignan, Jr.	Director
/s/ Charles K. Gifford 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/ 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, 1995 and 1994, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

Boston, Massachusetts
January 25, 1996