BOSTON EDISON
800 Boylston Street
Boston, Massachusetts 02199

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

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November 15, 1995
BECo 95-117

Document Control Desk
Director of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, DC 20555

License DPR-35
Docket 50-293

Dear Sir:

In accordance with 10CFR140.21 and the 1975 amendments to the Price Anderson Act (Public Law 94-197), Boston Edison is submitting the following:

1. Boston Edison Company Annual Report for 1994.

2. Boston Edison Company Form 10-Q for the quarter ended September 30, 1995 as filed with the Securities and Exchange Commission.

3. Cash Flow Forecast for the year 1996.

4. Narrative Statement of curtailment of capital expenditures.

Sincerely,

Robert J Weafer Jr

Enclosures

cc:

Mr. Ira P. Dinitz
Insurance Indemnity Specialist
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Senior NRC Resident Inspector
Pilgrim Nuclear Power Station

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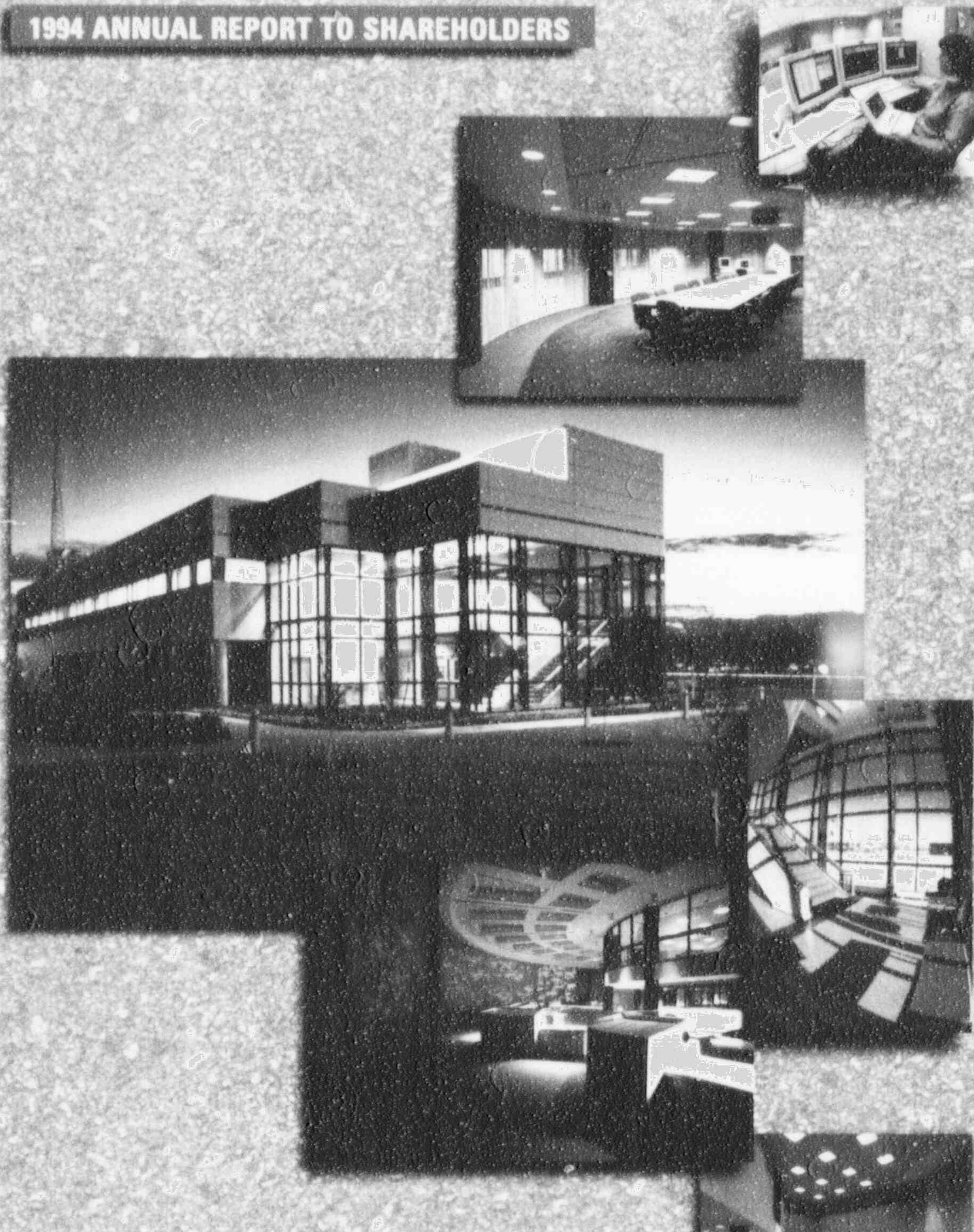
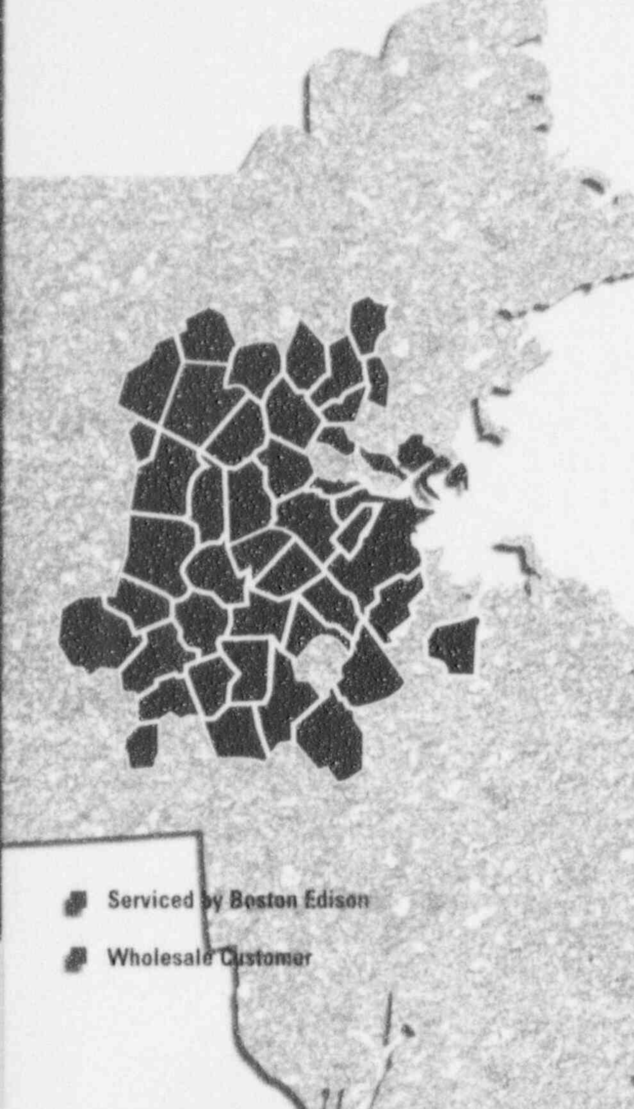
1994 ANNUAL REPORT TO SHAREHOLDERS



Boston Edison



FINANCIAL HIGHLIGHTS:

	years ended December 31, 1994	1993	% change
Operating revenues (000)	**$1,548,554**	$1,482,253	+ 4.5%
Income available for common stock (000)	**$109,257**	$102,513	+ 6.6%
Common shares outstanding - weighted average (000)	**45,338**	44,959	+ 0.8%
Common stock data:			
Earnings per share	**$2.41**	$2.28	+ 5.7%
Dividends declared per share	**$1.775**	$1.715	+ 3.5%
Payout ratio	**73%**	75%	− 2.7%
Book value per share	**$20.11**	$19.42	+ 3.6%
Return on average common equity	**12.1%**	11.9%	+ 1.7%
Fixed charge coverage (SEC)	**2.45**	2.22	+10.4%

Certain reclassifications and recalculations were made to the data reported in the prior year to conform to the method of presentation used in 1994.

CONTENTS:

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.

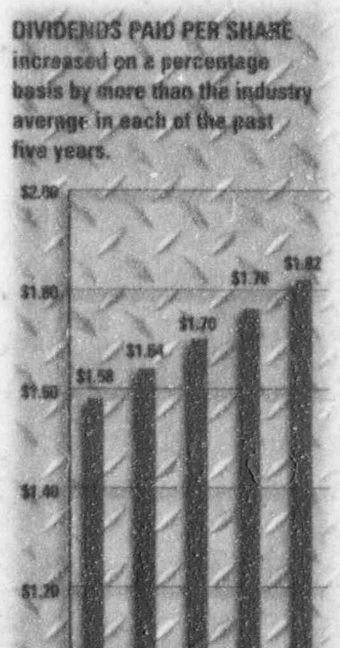
We also supply electricity to other utilities and municipal electric departments at wholesale for resale. About 87 percent of our revenues are derived from retail electric sales, 11 percent from wholesale sales and 2 percent from other sources.

ON THE COVER: OUR NEW ENERGY MANAGEMENT CENTER opened in January 1995. The facility gives employees the ability to control the delivery of electricity from our generating stations to our customers' homes. Members of the Energy Management Center Team include (from left) Ron Poindexter, Wendy Rueger, Bob Sullivan, Dick Zbikowski, Frank Donlan, Frank Flemming, Rick Fike and Mike Sanford.

DEAR SHAREHOLDER: Aggressive cost control, the use of new technologies, improvements in productivity and changes in work practices all contributed to another successful year in 1994 for Boston Edison. We achieved earnings growth of 5.7 percent, and continued a five-year trend of increasing your dividend, this time by 3.4 percent to $1.82, up from $1.76. This five-year pattern of increase places Boston Edison in the industry's top quartile for dividend growth, and reflects continued financial strength, excellent operating performance and a positive outlook for the future.

As the pace of industry change increases, we face an exciting future full of opportunity. We are striving to look less like a monopoly and more like a successful service and technology firm. Our future includes smaller, more efficient staff operations, strong alliances with business partners and the use of new technologies to lower costs, improve service to customers and position us to compete successfully.

COST CONTROL — We are controlling our costs successfully. In May, we signed new six-year contracts with our two union locals providing certainty as to wage adjustments and health care benefits, and gaining more flexibility in work practices. As a result of investments in improved technologies we realized significant gains in reliability and productivity, enabling us to reduce our work force by 371 positions, or 8.4%, in 1994. We accomplished this through a combination of attrition and by selectively eliminating positions and functions. Also, we consolidated the Marketing and Sales organizations, outsourced certain functions, and streamlined operations in line organizations.



Other measures will trim millions of dollars from Company expenses. Two service centers will be closed in 1995 with functions consolidated at remaining centers. Improvements in materials management enable us to reduce inventory and close three warehouses. By holding less inventory, streamlining major work processes, standardizing sizes and types of materials and employing just-in-time inventory techniques, we will save $7 to $10 million annually. And, we are working with vendors like General Electric and Westinghouse to determine the price and availability of required supplies quickly and to place orders with minimal human intervention and paperwork.

Using new technologies, the bill collection process has been improved, increasing cash flow by some $4 million. Our fleet of passenger vehicles has been reduced by 40 percent, or 250 cars. It is noteworthy that these savings are being identified and realized by cross-functional teams trained in and charged with finding solutions. They are doing just that.

An employee team developed a streamlined two-step, one-day process for new customer installations. Combining new technologies with work practice changes, this new process both reduces costs and improves service. Other employees reduced system maintenance outage times and, in doing so, lowered labor costs, minimized customer inconvenience and improved reliability.

PLANNING — Our efforts to achieve greater flexibility in resource planning produced positive results, as well. In an important decision from the Massachusetts Department of Public Utilities (MDPU), our plan to meet future demands for electricity through a flexible resource acquisition strategy was approved. The MDPU agreed that new supplies of electricity are not needed through the year 2000, and approved our request to issue an Options RFP (a flexible contract giving us the option to buy power at a predetermined price), calling it, "an innovative approach to resource planning."

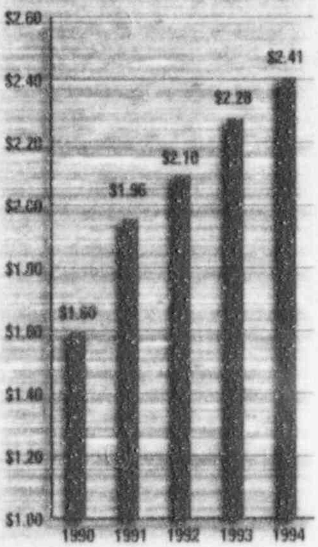
In November, we eliminated a cumbersome first mortgage bond indenture, providing us with greater financial flexibility. We are one of only a few electric utilities to have no first mortgage bonds.

OPERATIONS — Our generating plants continued to perform well. The Pilgrim plant's 1994 "report card" from the Nuclear Regulatory Commission was its best ever, placing it in the top quartile of plants nationwide. Once again, Pilgrim earned incentive revenues by exceeding 1994 performance targets set by the MDPU. Future performance is expected to show continuing improvement because of the elimination of planned maintenance overhauls between refueling.

In 1994, the fossil-fuel generation system achieved the second highest unit availability in the system's history, significantly improving the percentage of time generating units are available to produce power.

Also, major environmental modifications were completed at our power station in South Boston. As a result, the Company continues to have the cleanest generating plants in New England. We are in compliance with the Federal and State Acid Rain regulations through the year 2000, while other utilities still must invest to reduce emissions from their plants.

EARNINGS PER SHARE FROM OPERATIONS rose 5.7% in 1994.



COMPETITION — Success in a competitive environment is measured in wins and losses, and we've been winning. One of the reasons is the quality of the sales and marketing team, a blend of professionals with extensive experience in competitive situations and seasoned Boston Edison veterans. This year we gained more than 40 megawatts in new customer load, and had no significant customer losses.

In the wholesale market, all existing customers are under contract through at least the year 2002, and we added a new customer with significant growth opportunity, the Town of Braintree. In the retail market, we acquired new business from former steam customers and expanded existing customer relationships through new other-side-of-the-meter services.

TECHNOLOGY — With a focus on meeting the changing needs and expectations of customers, we're looking for technological solutions that will enable us to reduce costs, improve and expand service and add value to the customer relationships.

A new energy management center and the modeling of the future distribution business, both described later in the report, are just two examples. Others can be found throughout the Company.

In information, in operations, in sales, in all aspects of field services, technologies are being identified and deployed to enhance our relationship with our customers.

Our course over the past five years has been one of steady improvement. We have successfully executed our operating plans and, in many cases, exceeded our goals. Our management team is strong and creative, we have achieved financial strength and flexibility, and we have the strategies in place to win in what we know will be a changing, more competitive environment. We are confident that whatever changes come our way, we will remain successful.

In closing, one change in 1994 that affected us both was the retirement of Bernard W. Reznicek. First as president and then as chairman and chief executive officer, Bernie brought clarity to our management processes, and helped us to define excellence for our operations, to empower employees to perform beyond normal boundaries and to enhance our reputation with regulators and the financial community. He is now dean of the business school at Creighton University in his native Omaha, Nebraska, and serves on our Board of Directors. We wish him well.

Tom May

Thomas J. May
Chairman and
Chief Executive Officer

G W Davis

George W. Davis
President and
Chief Operating Officer

Questions are being raised about the changes in our industry and what impact they're having on Boston Edison. In this section, **Company Chairman and CEO Tom May offers his views** on industry change and what shareholders should expect in the future.

What's driving the debate on how to restructure the electric utility industry?

It's a combination of factors. First, the structure of vertically integrated utilities responsible for all aspects of generation, transmission and distribution no longer makes sense. The current system of regulation was largely created in the 1930's when rapid expansion of the electric system was critical to the nation's economic growth. Today, that's no longer the case. In fact, new, more efficient generation technologies and lower costs, coupled with legislation that started removing barriers to market entry in the late 1970's, have already created a competitive commodity market for electricity. In addition, transmission systems, as a matter of Federal policy, are moving towards a common carrier system (like the U.S. highway system) with equal access by all. For both generation and transmission, there are many questions that still need to be answered to assure that stakeholder groups are protected, but the direction has clearly been set.

You can add customer expectations to the technology, economics and public policy drivers. Customers want choice and the benefits of competition. Ours is the last of the regulated industries to go through this process. Customers want, and expect to be able to make, choices in the future about their electricity supplier and the services it will offer.

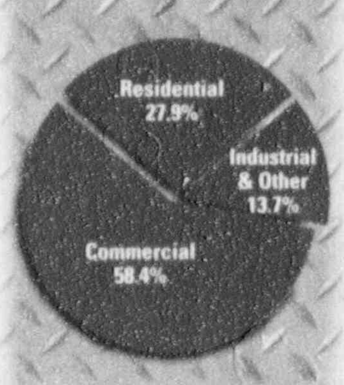
How long will this transition take?

There's a lot of speculation and uncertainty about this. Nearly two dozen states and the Federal government are today addressing the complex issues surrounding industry restructuring. In some cases, there have been relatively bold proposals, followed by a period of reflection, suggesting a somewhat slower approach. In other cases, as here in Massachusetts, the approach has been very deliberate, very methodical. The Massachusetts Department of Public Utilities is asking the right questions and bringing the key stakeholders to the table. This makes a lot of sense, and I support the department's approach.

Our goal should be to maximize the benefits of competition to all customers, while minimizing the potential harm to the various stakeholders. This suggests to me an evolutionary process. We need to sort out the complex regulatory and economic obligations created under one regulatory scheme as we move to another. And I think this will take a number of years. At the same time, I believe choice will begin with our largest customers, probably within the next five years.

In the meantime, some of the same technologic, economic and customer factors driving industry restructuring are already creating competition. Sophisticated customers will look at all options to reduce costs in a highly competitive national and global economy. So regardless of how long it takes to restructure the industry, we have to be prepared to compete successfully today to hold onto and expand our customer base.

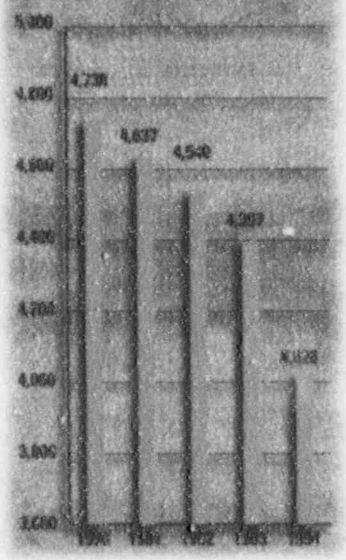
Our RETAIL CUSTOMER MIX is stabilized by the commercial and residential sectors which help minimize effects of regional economic swings.



What's your vision of a restructured industry?

I think the excitement will be in the retail distribution business. Generation is a commodity, the competition will be intense, and the margins will be small. Utilities will continue to be players, in many cases through alliances, but the number of players will be large. Transmission will simply become the interstate highway system for moving power from the generators to the retail distribution companies and to individual customers who have a choice of supplier. There will be ready access to the system, rates will be published and generators, utilities and customers will move on and off relatively easily. There will be traffic jams and constraints, but those will get worked out.

TOTAL NUMBER OF EMPLOYEES decreased 8.4%, in line with our plans to pare down to 3,600 employees by the year 2000.



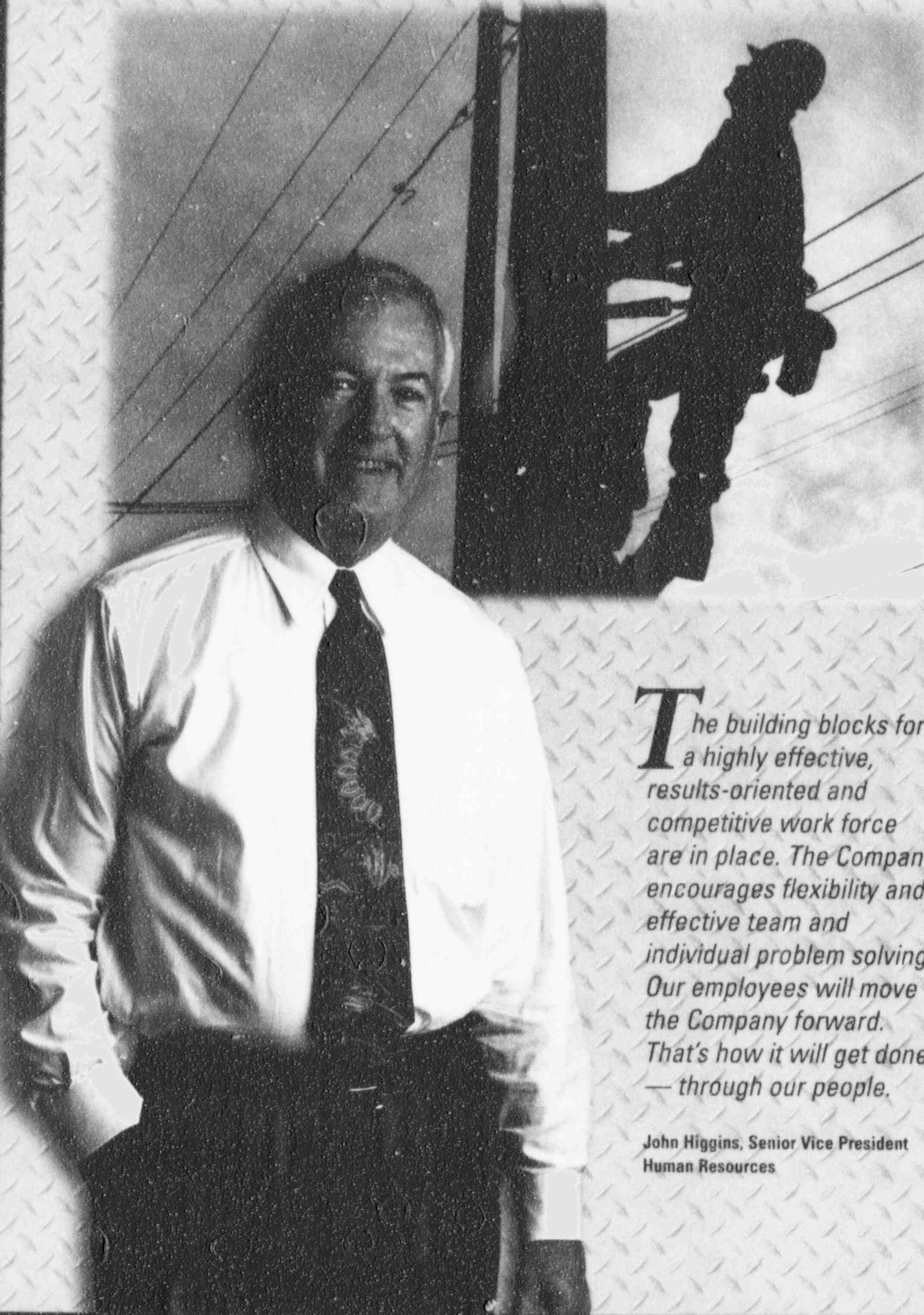
Just as new technologies, improved economics and customer choice are transforming the industry, so too will they transform the retail distribution business. While most customers will continue buying electricity from us, all customers will continue to have electricity delivered by us. But that's only the beginning of the relationship. We will transform our existing distribution business into an integrated client services network. Automation and storage technologies will allow us to bring new levels of efficiency and lower costs. Information technologies will enable customers to make up-to-the-minute buying decisions and allow us to monitor and control their use based on their choice of services and products. Meters will be replaced by computerized devices, and customers won't have to wait until next month to know how much they have used and at what cost. Alliances with companies that market and move information are likely to expand the nature and scope of services we can offer. So the prospects for what this industry will look like in ten years are truly exciting, once we work through the rules of transition.

What role is Boston Edison playing in the changes?

We have a vital role on behalf of all of our stakeholders — our shareholders, our customers, our employees and the communities we serve. If the interests of those stakeholders are to be protected, the transition should be orderly to assure that no single stakeholder benefits at the expense of the others. We are fortunate to have already operated under an incentive rate structure in generation, and our managers are committed to freezing base rates through the year 2000. We also have a seat at the table in every major forum looking at industry restructuring as it could affect Massachusetts. In fact, we've proposed a regulatory transition concept that would separate generation pricing from transmission and distribution. It would provide for generation to be market priced, allow for recovery of any generation assets currently recorded above their market value through transmission and distribution pricing, and establish incentives to improve utility efficiency on the distribution system. The reactions we've had from a number of key policymakers have been positive. Ours is just one approach, however, and it's important that we be part of the debate on the full range of proposals now under consideration.

What should shareholders expect the next few years?

Shareholders should expect us to work diligently at continuing the steady pattern of financial progress we've achieved over the past five years. And they should expect us to move into a more competitive environment by both influencing the outcome of the debate on how to restructure the industry and by being aggressive in retaining and attracting customers. In addition, we'll be looking for new revenue sources from expanded products and services. As you'll see elsewhere in this report, we are controlling costs, winning in competitive situations, seeking new business opportunities and enhancing customer relationships. We have a solid foundation for our participation in the debate on industry restructuring and for responding to, and benefiting from, the competitive pressures that are already emerging. We will continue to pursue our objective of outperforming the industry.



The building blocks for a highly effective, results-oriented and competitive work force are in place. The Company encourages flexibility and effective team and individual problem solving. Our employees will move the Company forward. That's how it will get done — through our people.

John Higgins, Senior Vice President
Human Resources

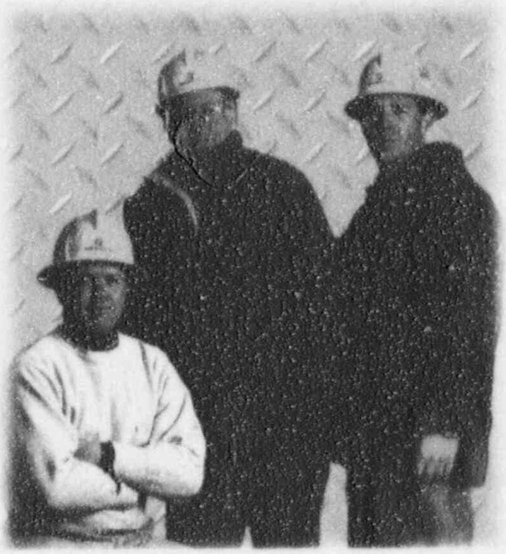
THE EMPLOYEE OF THE FUTURE will possess multiple skills, be flexible and be expected to undertake more tasks. Specialized jobs and narrowly defined job classifications are being replaced, and employees are being asked and empowered to take more personal responsibility for improving customer service. For example, Company and union leadership worked together with 70 substation operators and mechanics to create one new job combining both sets of skills. The new classification provides employees with new flexibility to get the job done, benefits the Company through more efficient use of employee resources, and benefits customers by quicker response at lower cost.

Utilities used to have long lead times to plan for the future. Stability was the norm, and the premium on speed was small. But the rules are changing, and speed and flexibility are required attributes in a competitive market. We are achieving flexibility and speed through our focus on cross-functional teams for meeting customers' needs, the use of technologies and a cost consciousness shared by all employees.

In this example, as in so many others, the key to success is Mutual Gains Bargaining, a technique for understanding what's at stake before negotiating an agreement that most closely meets the needs of all involved. It sounds simple enough, but the effects have been very dramatic.

In May 1994, our labor unions signed six-year contracts. They include a number of productivity and benefits improvements, along with fair wage increases, that would not have been possible without Mutual Gains Bargaining. The contracts provide both flexibility and stability as a result of a shared view of emerging competition.

In addition to well-trained and flexible employees, we will continue to focus on technology to help employees meet competitive challenges. In 1994, we initiated an interactive television simulation module to help first line supervisors face real-life situations. For example, the module presents a supervisor with 50 homes without power at the end of a shift. The supervisor answers a series of questions and makes decisions. The module takes the "answer", evaluates it, and presents a number of other scenarios that might have been considered. Such training broadens employees' thinking, enhances decision-making and increases confidence.



From left: John Prior, Warren Farnsworth and Steve Prosper, a self directed work team given the autonomy to act on behalf of the customer.

OUR APPROACH TO SERVING CUSTOMERS is changing.

We are becoming a business partner, not just an electricity provider to our commercial and industrial customers. We are working to understand their businesses so that we can be a more effective partner in meeting their needs. We are using technology to improve service, lower costs and enhance our customers' internal operations. In doing so, we will add value to the relationship, which will help us retain and attract customers. The effects of changes in the industry are evident, and we are responding well. In 1994 we gained over 40 megawatts of new load and had no significant customer losses.

In anticipation of a tougher, more competitive future, we structured sales and marketing functions to ensure the most effective response to the varying needs of customers. We recruited seasoned sales and marketing professionals from competitive industries. The combining of highly skilled long term Boston Edison employees and sales professionals from competitive industries has produced an exceptionally strong team. We are positioned to develop relationships more fully and to better anticipate needs because we understand our customers' businesses. We are able to offer total energy solutions to customers, going well beyond the traditional utility scope, to help them improve their own competitive positions.

We will develop alliances with vendors, contractors, manufacturers and other business partners to offer our customers a diverse portfolio of products and services. For example, a multifaceted effort with the Massachusetts Water Resources Authority goes well beyond supplying electricity. One aspect of the partnership involved the installation of a 115 kv submarine cable and the construction of backup generators to serve a new waste treatment facility for Greater Boston. In addition, the Company and MWRA have entered into a three-year operation and maintenance training agreement which alone is valued at more than $2.5 million. Boston Edison personnel are using their expertise to train MWRA personnel. Other aspects of the relationship include energy efficiency upgrades and environmental technologies.

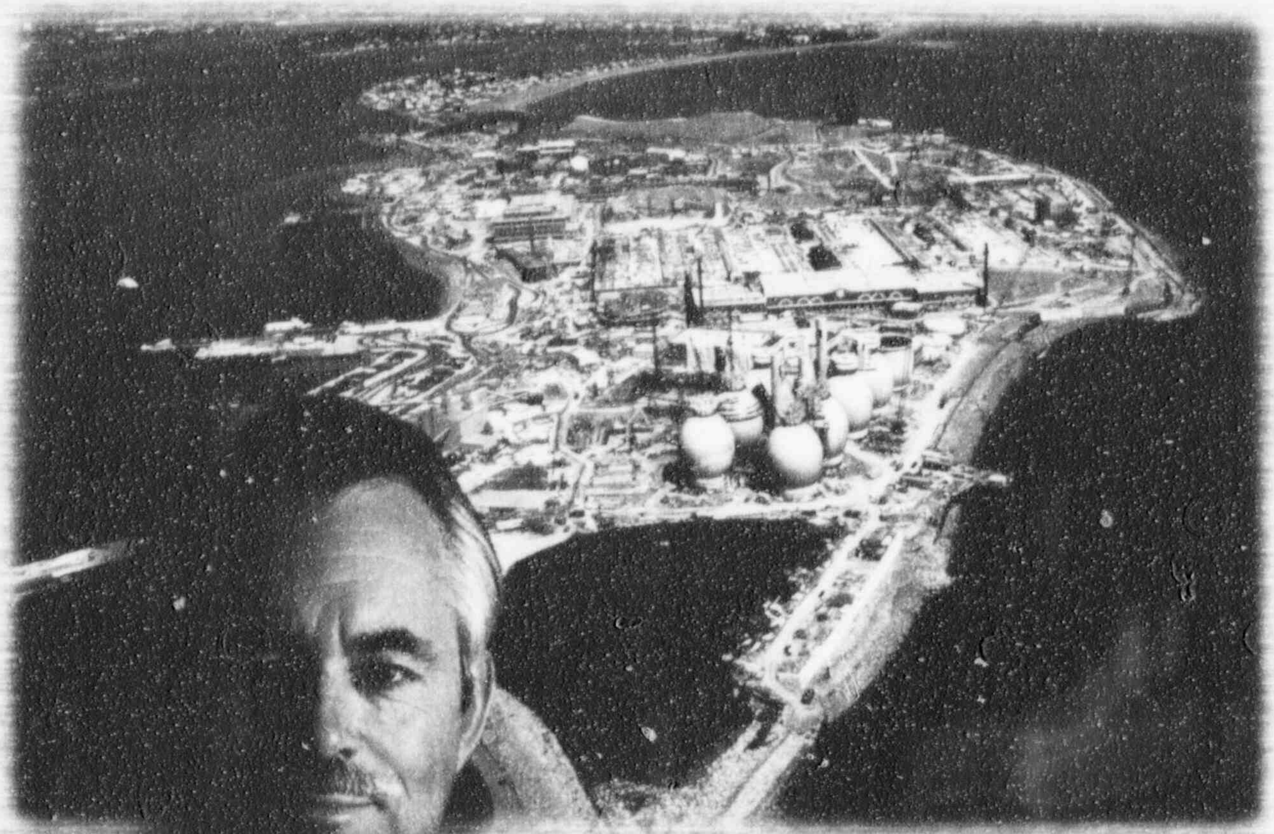
In another example of alliance building, the Company worked with city and state governments to put together a comprehensive proposal which led to the restart of a large paper company in Boston. The company will create 120 jobs and add 9 megawatts of load to our system.

The bottom line is that business customers want help in meeting their business needs. So, we must be more creative, act more quickly, become a part of our customers' total business solutions, and stay focused on the basics of customer service.

Part of the team responsible for planning, constructing and delivering service to the new MWRA wastewater treatment plant. Pictured from left: Jerry LaFond, Bill Polin, Rob Billet, Dan Charbonnet, Charlene Greene, Tim Crowell, and Tony Gervasi.

Customers want quality and value. Providing the right mix of both will win customer loyalty. That is why we are working closely with our customers to understand, not only their energy needs, but also their business needs. This way, we can offer operating efficiencies, environmental solutions and new technologies to suit individual situations. In other words: A total energy solution based on innovation and expertise.

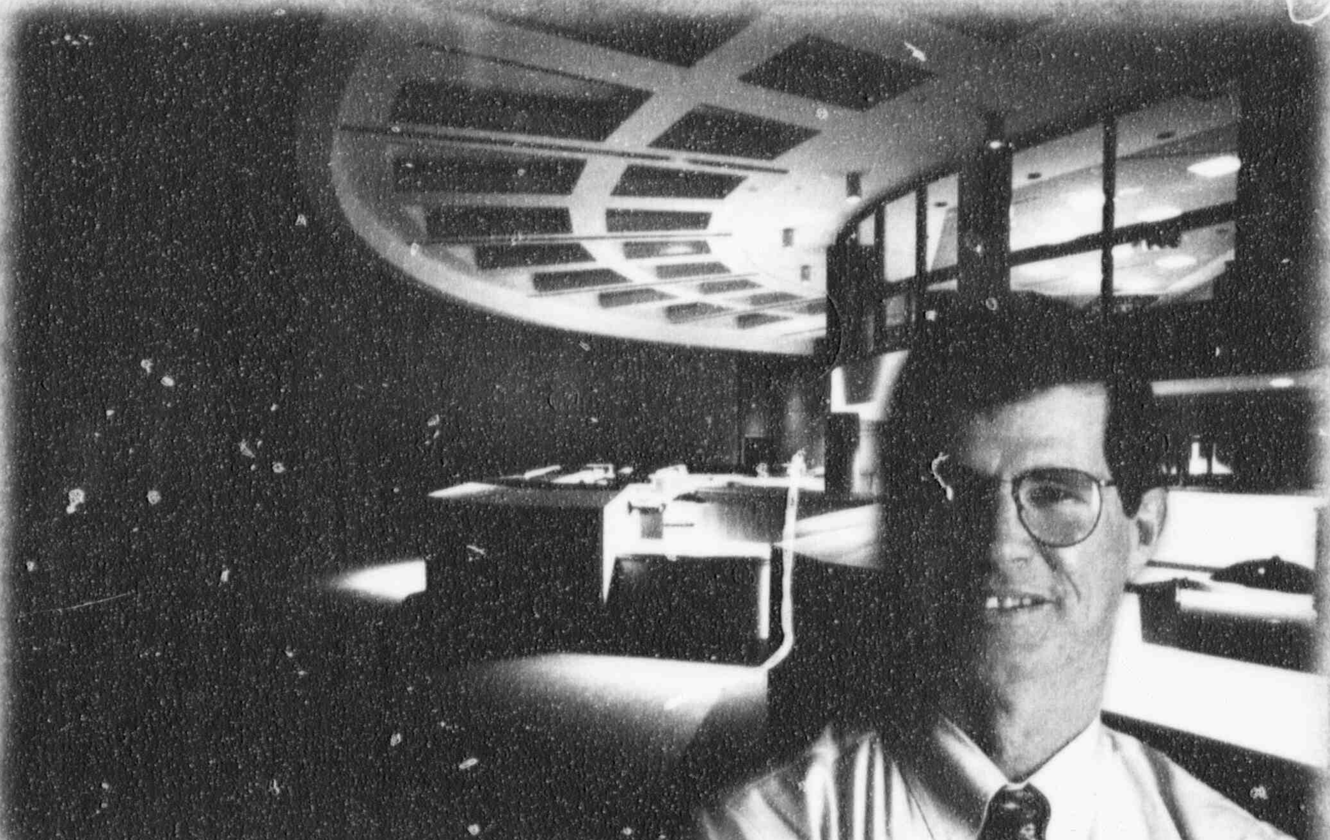
Pictured below is the MWRA wastewater treatment facility located on Deer Island.



Customers want the ability to make a choice. Tomorrow they will have that choice in one form or another. For some of the largest customers, the choice will be over their energy provider, but for all customers they will be able to exercise some choice over an array of products and services delivered over an integrated customer services network. Faced with these choices, customers will make electricity purchase decisions based on the value they're receiving.

L. Carl Gustin, Senior Vice President
Marketing and Corporate Relations

Pictured below is the interior of the new Energy Management Center which began operations in January 1995.



Our future core business will provide customers with energy, information and a variety of services over our lines. New opportunities for products and services will occur much faster than in the past. Our business successes will feature superior control of costs, more flexible employee relationships, selected use of technology, strategic alliances with suppliers and customers, and innovative practices which create new business opportunities.

Ronald Ledgett, Senior Vice President
Power Delivery

AS THE UTILITY INDUSTRY CHANGES,

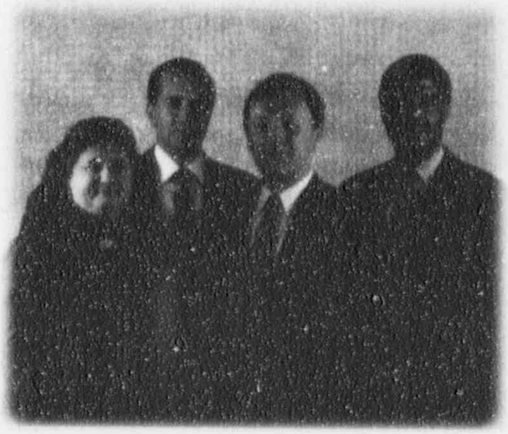
exciting new business opportunities will result. We are well positioned to grow with the changes and benefit from the results in our own service territory, and possibly beyond.

As the industry changes, we will play a critical role in furthering the interests of all our stakeholders. We want to take a leadership role in shaping the future of the electric utility industry. We will attempt to maximize the benefits of industry restructuring to all stakeholders. We have a solid foundation for our participation in the key debates on industry change.

In the past two years, we realigned our traditional electricity distribution functions to address the concerns of customers and communities more effectively. Now, commitments to customers and communities are made by employees who have the resources, the authority and the accountability to make commitments and carry them out. Whether a routine service call or a response to an emergency, customer concerns and commitments to customers are matters of greatest importance to all employees.

Our strategy is to make investments in new technologies that address customer concerns, reduce operating costs, increase the utilization of our assets, and create new sources of revenue. We will invest approximately $4 million over the next two years to demonstrate technologies and service options for the distribution business of tomorrow. We intend to leverage Boston Edison's significant investment in right-of-way and distribution circuits to profit from the burgeoning "information highway."

In January of this year, we inaugurated our new state-of-the-art energy management control center, pictured on the cover. The $25 million center features interactive computer mapping, and advanced control and telecommunications technology to monitor electrical system performance, and provide new services at customer facilities. A new substation in South Boston and other system improvements in 1995 will retire aging distribution circuits, resulting in reduced operating cost and improved customer service.



Boston Edison representatives leading the discussions on forming a Regional Transmission Agreement and restructuring the New England Power Pool. Pictured from left: Joyce Wood, Phil Legrow, Ed O'Brien and Joel Kamya.

IT IS IMPORTANT TO UNDERSTAND

IT IS IMPORTANT TO UNDERSTAND the cost of our product and to act based on reliable information. Managers are analyzing their own business units in new ways. Managers throughout the organization will now be responsible for revenues, expenses and contribution for their individual business units.

Based on a competitive business analysis, managers will determine, for instance, if their decisions will increase revenues, reduce costs or improve operations. In understanding the implications of their decisions, managers will be armed with timely, action-oriented information.

Our employees are challenged and time after time find creative approaches to streamline processes and improve profitability.

Members of the cross-functional team working on the two-year Distribution Circuit Business Pilot Project. From left: Ben Tucker, Mike Cooper, Virginia Walker, Frank Gaffney, Frank Silvia, Rob Becker and Annmarie Svingen.

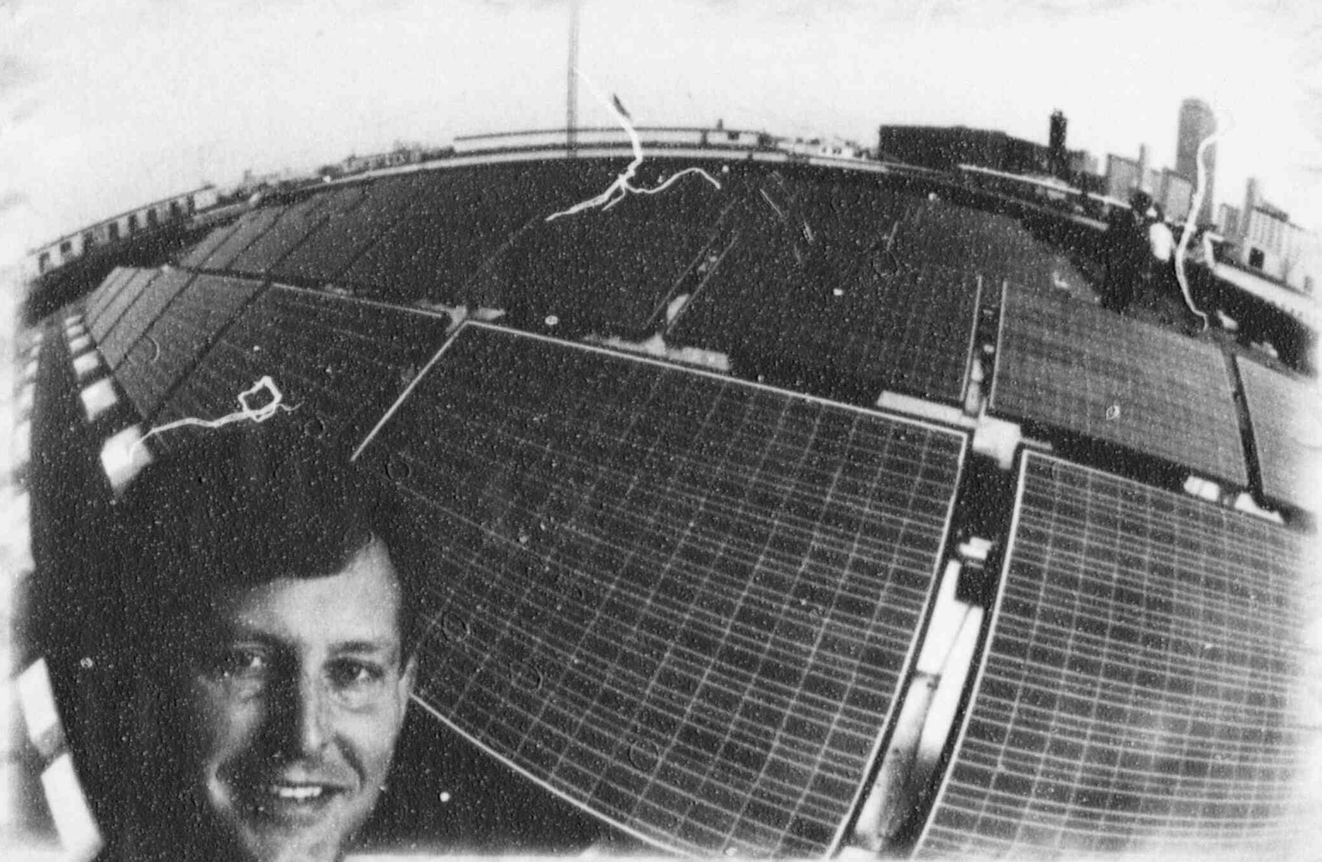
Using technology to access information is also important to our success. In 1994, we structured our information systems group to focus information systems (IS) personnel on helping their internal customers, managers and employees, with any IS issue. The reorganization marks a significant shift to a more flexible client-server (personal computer based) environment.

The supply management system was also assessed to identify efficiency improvements and improve ways of doing business. The results have been excellent: working with vendors and thinking about our business differently, we have been able to improve operations, reduce inventory levels, reduce paperwork and procedures, and eliminate three warehouses. Creative vendor partnerships with suppliers like General Electric and Westinghouse have led to an integrated system that determines availability and price of supplies and places timely orders with minimal human intervention or paperwork.

We will continue our commitment to new technology, improved information and creative thinking to help control costs, improve service and assure future success.

We will simultaneously strive for cost savings and for smart investments in new technologies. The wires into our customers' homes and businesses will one day carry more than just electricity. They will also carry services and information; another link to the information highway. The right technologies improve reliability, add value for the customer and provide potential new revenue sources. It's an investment in our competitive future.

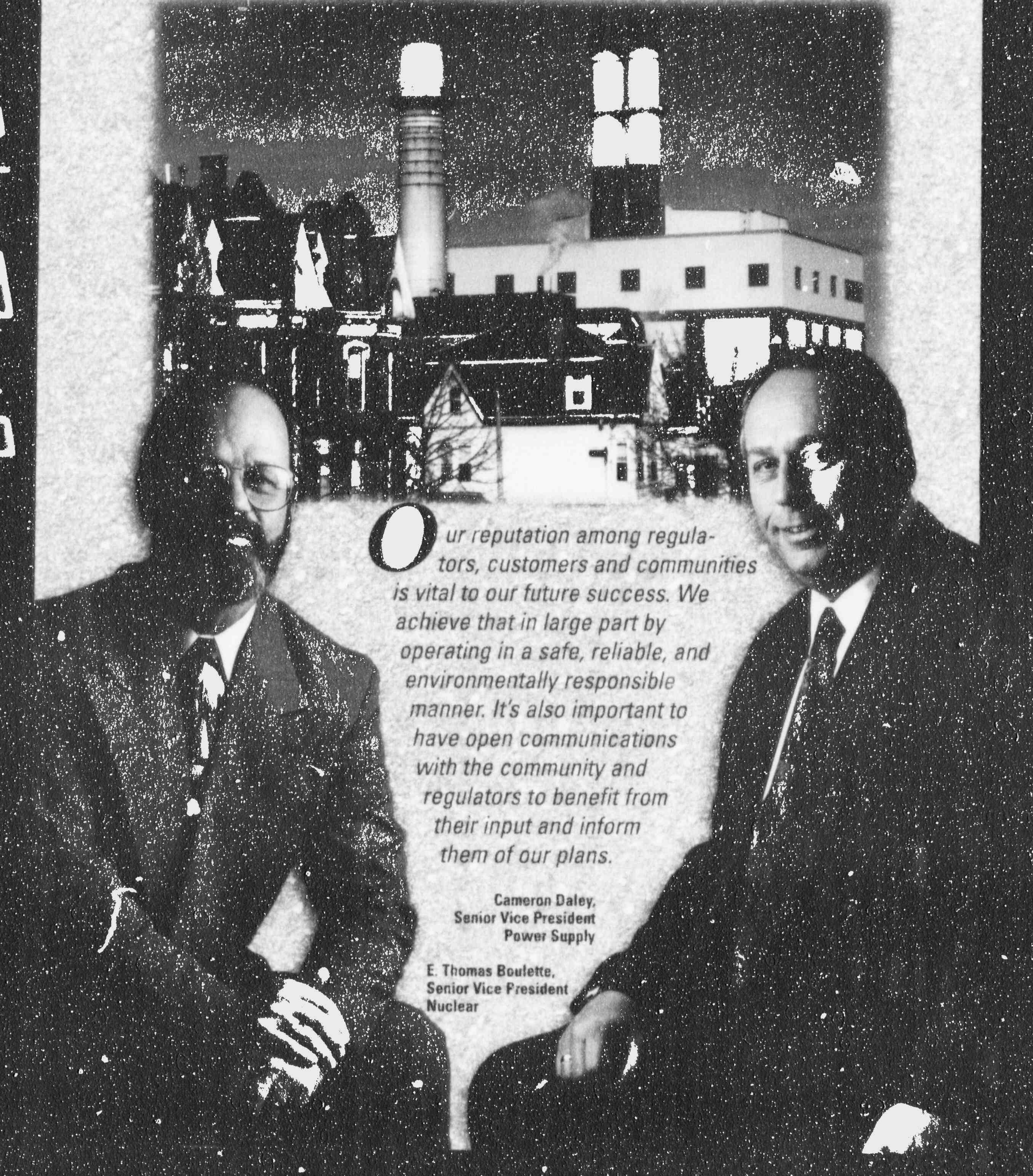
Pictured below is a photovoltaic system that generates electricity using energy from the sun. This state-of-the-art pilot project was co-funded by Boston Edison.



As the details of regulatory change unfold, we are actively preparing our managers for the business of the future through improved information and better application of technology. Gone are the days when we could look at our business operations as a whole, total up the cost, add an appropriate profit, and charge customers the portion regulators approved. Our future will depend on our ability to be the provider of choice for customers.

Charles Peters, Senior Vice President Finance

Pictured below is the New Boston power plant located in South Boston.



Our reputation among regulators, customers and communities is vital to our future success. We achieve that in large part by operating in a safe, reliable, and environmentally responsible manner. It's also important to have open communications with the community and regulators to benefit from their input and inform them of our plans.

Cameron Daley,
Senior Vice President
Power Supply

E. Thomas Boulette,
Senior Vice President
Nuclear

In every community where we operate a plant, we must remember that we are neighbors and guests. Making low-cost power has to be balanced with many other things, including top-notch reliability, safety and environmental practices. Additionally, our relationship with our communities is a priority.

A COMPETITIVE POWER GENERATION MARKET

emphasizes safe, reliable and low cost power. Every employee knows that our reputation among regulators, customers and the communities in which we operate is also important.

The Pilgrim Nuclear Power Station's 1994 "report card" from the Nuclear Regulatory Commission was its best ever, placing it in the top quartile of plants nationwide. Also, at the Pilgrim plant, we are decreasing costs by improving maintenance planning and reducing down time for maintenance work. Beginning in 1995, we will refuel the plant every two years and eliminate planned maintenance outages between refueling. This performance combined with a reduction in the length of each outage will increase our average capacity factor to 83%, placing us in the top group of plants nationwide and resulting in an annual cost savings of $4.5 million.

On the fossil-fuel generation system, we've also improved operations and reduced costs. We streamlined work practices and consolidated maintenance activities into one group resulting in reduced staffing levels and cost savings totalling $2 million. Our unit overhauls were completed ahead of schedule and 9% under budget. We've also negotiated five-year contracts which cut natural gas transportation prices in half, and will continue to look for every opportunity to decrease the cost of our product and ensure our success.

We completed important environmental modifications at our plant in South Boston in 1994. As a result, future expenditures to meet Federal and State Clean Air Act requirements are expected to be minimal. We also installed a new, state-of-the-art environmental management system across the company.

We have taken a leadership role in working with public and municipal utilities, non-utility generators, power marketers and regulators to build a consensus on what a "regional transmission" agreement should look like, and how the interests of our customers and shareholders can best be served.

As more players try to fight for a piece of the generation market, we'll continue to focus on managing ourselves efficiently and effectively, remain an active player in community affairs and ensure our customers and shareholders are actively represented at the table of regulatory change.

Members of the Pilgrim Station outage review team preparing for this year's planned refueling outage. From left: Bruce VanFleet, Nancy Desmond, Stuart Minahan, Tom Trepanier, Mark Potkin and Steve Geary.

Management's Discussion and Analysis

Regulatory Proceedings

Retail settlement agreements

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

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

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

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

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

Results of Operations

1994 versus 1993

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

Operating revenues

Operating revenues increased 4.5% over 1993 as follows:

(in thousands)

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

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

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

Operating expenses

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

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

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

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

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

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

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

Other income

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

Interest charges

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

1993 versus 1992

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

Operating revenues

Operating revenues increased 5.0% over 1992 as follows:

(in thousands)

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

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

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

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

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

Operating expenses

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

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

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

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

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

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

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

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

Interest charges and preferred and preference dividends

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

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

Financial Condition

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

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

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

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

Liquidity

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

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

Outlook for the Future

Electricity sales

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

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

Competition

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

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

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

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

Resource regulation

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

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

Non-utility business

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

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

Other Matters

Environmental

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

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

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

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

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

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

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

Litigation

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

Executive Office Changes

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

CONSOLIDATED STATEMENTS OF INCOME

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

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

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

CONSOLIDATED BALANCE SHEETS

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

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Cash paid during the year for:			
Interest, net of amounts capitalized	$ 108,462	$ 103,720	$ 113,076
Income taxes	$ 46,074	$ 30,305	$ 10,095

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A. Significant Accounting Policies

1. Basis of Consolidation and Accounting

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

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

2. Revenues

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

3. Forecasted Fuel and Purchased Power Rates

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

4. Depreciation and Nuclear Fuel Amortization

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

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

5. Amortization of Deferred Nuclear Outage Costs

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

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

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

7. Allowance for Funds Used During Construction (AFUDC)

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

8. Cash and Cash Equivalents

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

9. Allowance for Doubtful Accounts

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

10. Regulatory Assets

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

Regulatory assets consisted of the following:

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

Note B. Retail Settlement Agreements

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

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

Note C. Income Taxes

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

Accumulated deferred income taxes consisted of the following:

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

No valuation allowances for deferred tax assets are deemed necessary.

Components of income tax expense were as follows:

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

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

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

Note D. Nuclear Decommissioning and Nuclear Waste Disposal

1. Nuclear Decommissioning

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

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

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

2. Spent Nuclear Fuel

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

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

3. Low-Level Radioactive Waste

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

4. Other Nuclear Units

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

Note E. Pensions, Other Postretirement and Postemployment Benefits

1. Pensions

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

Net pension cost consisted of the following components:

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

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

We used the following assumptions for calculating pension cost:

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

The pension plan's funded status was as follows:

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

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

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

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

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

2. *Other Postretirement Benefits*

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

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

Net postretirement benefits cost consisted of the following components:

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

We used the following assumptions for calculating postretirement benefits cost:

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

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

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

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

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

3. Postemployment Benefits

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

Note F. Eminent Domain Taking

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

Note G. Cancelled Nuclear Unit

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

Note H. Capital Stock and Indebtedness

Capital Stock

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

Dividends Declared per Share

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

Indebtedness

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

I. Common Stock

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

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

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

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

2. *Cumulative Non-Mandatory Redeemable Preferred Stock*

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

3. *Cumulative Mandatory Redeemable Preferred Stock*

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

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

4. *Long-Term Debt*

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

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

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

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

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

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

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

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

5. *Short-Term Debt*

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

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

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

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

Note I. Fair Value of Securities

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

Nuclear decommissioning trust

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

Cash and cash equivalents

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

Mandatory redeemable cumulative preferred stock, sewage facility revenue bonds and unsecured debt

The fair values of these securities are based upon the quoted market prices of similar issues. Carrying amounts and fair values as of December 31, 1994 are as follows:

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

Note J. New Accounting Pronouncement

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

Note K. Commitments and Contingencies

1. Capital Commitments

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

2. Lease Commitments

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

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

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

3. Hydro-Quebec

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

4. Yankee Atomic Electric Company

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

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

5. *Nuclear Insurance*

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

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

6. *Litigation*

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

7. *Hazardous Waste*

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

Note L. Long-Term Power Contracts

1. Long-Term Contracts for the Purchase of Electricity

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

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

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

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

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

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

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

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

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

2. Long-Term Power Sales

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

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

(a) Subject to certain adjustments.

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

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, 1994 and 1993 and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1994. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994 and 1993, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 1994, in conformity with generally accepted accounting principles.

Coopers & Lybrand, L.L.P.

Boston, Massachusetts
January 26, 1995

Selected Consolidated Quarterly Financial Data (Unaudited)

(in thousands, except earnings per share)

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

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 1994 and 1993 and the dividends declared per share during each of those quarters:

	1994			1993		
	High	Low	Dividends	High	Low	Dividends
First quarter	$ 29 7/8	$ 26	$ 0.440	$ 30 1/2	$ 26 3/8	$ 0.425
Second quarter	29 1/8	25 1/4	0.440	30 7/8	27 7/8	0.425
Third quarter	27 5/8	22 3/4	0.440	32 5/8	29 3/4	0.425
Fourth quarter	24 1/4	21 1/2	0.455	32 1/4	27 7/8	0.440

Selected Consolidated Operating Statistics (Unaudited)

	1994	1993	1992	1991	1990
Capacity - MW:					
New Boston Station	**760**	760	760	760	760
Pilgrim Station	**669**	670	670	670	670
Mystic Station	**1,006**	1,006	1,005	1,015	1,014
W.F. Wyman Unit 4	**36**	36	36	36	36
Jet turbines	**287**	283	281	281	281
Total	**2,758**	2,755	2,752	2,762	2,761
Contract purchases	**1,035**	938	1,157	1,293	924
Contract sales	**(373)**	(283)	(303)	(293)	(173)
Net capability at year-end	**3,420**	3,410	3,606	3,762	3,512
Net capability at peak - MW	**3,484**	3,663	3,587	3,695	3,505
Capability responsibility to NEPOOL at peak - MW	**3,306**	3,190	3,396	3,311	3,393
Edison territory:					
Hourly peak - MW	**2,798**	2,662	2,545	2,652	2,548
Load factor	**58.9%**	60.5%	62.5%	60.0%	62.2%
Generating station economy (BTU/net kWh)	**10,408**	10,345	10,234	10,331	10,403
Average cost of fuel (Company) - $ per million BTU:					
Fossil	**2.321**	2.504	2.467	2.402	2.555
Nuclear	**0.501**	0.507	0.522	0.562	0.591
Composite	**1.613**	1.620	1.669	1.805	1.915
Capability (net kW):					
Fossil	**84%**	84%	81%	81%	81%
Nuclear	**16%**	16%	19%	19%	19%
Generation (system kWh excluding interchange):					
Fossil	**75%**	68%	69%	70%	72%
Nuclear	**25%**	32%	31%	30%	28%
Utility plant ($ in 000's):					
Expenditures	**198,760**	246,763	213,827	202,589	240,902
Retirements	**45,673**	34,147	34,036	30,333	27,180
Accumulated depreciation	**1,344,452**	1,258,359	1,177,294	1,097,991	1,015,371
Depreciable plant	**3,994,212**	3,841,752	3,567,160	3,488,269	3,277,616
Number of utility employees at year-end	**4,026**	4,397	4,540	4,637	4,738

Certain reclassifications were made to the data reported in prior years to conform with the method of presentation used in 1994.

Selected Consolidated Sales Statistics (Unaudited)

	1994	1993	1992	1991	1990
Electric energy (kWh in thousands):					
Sources (system output):					
Generated	**9,428,931**	9,787,092	11,679,824	10,602,110	12,744,238
Purchased	**5,920,065**	5,326,224	5,449,225	4,651,101	3,305,491
New England Power Pool	**1,535,335**	1,575,310	932,121	1,274,522	1,065,731
Total	**16,884,331**	16,688,626	18,061,170	16,527,733	17,115,460
Disposition:					
Commercial	**7,478,631**	7,263,358	7,178,281	7,143,484	7,178,134
Residential	**3,534,372**	3,477,870	3,413,252	3,386,681	3,427,410
Industrial	**1,539,385**	1,580,969	1,671,564	1,685,184	1,743,848
Other (a)	**130,721**	145,242	292,510	279,540	275,213
Total retail sales	**12,683,109**	12,467,439	12,555,607	12,494,889	12,624,605
Wholesale and contract sales (a)	**2,367,589**	2,272,669	2,517,247	1,660,082	1,674,114
New England Power Pool	**725,439**	877,978	1,898,059	1,252,797	1,885,165
Total system	**15,776,137**	15,618,086	16,970,913	15,407,768	16,183,884
Miscellaneous usage	**1,108,194**	1,070,540	1,090,257	1,119,965	931,576
Total	**16,884,331**	16,688,626	18,061,170	16,527,733	17,115,460
Kilowatthours - annual growth:					
Commercial	**3.0%**	1.2%	0.5%	(0.5)%	1.2%
Residential	**1.6**	1.9	0.8	(1.2)	0.4
Industrial	**(2.6)**	(5.4)	(0.8)	(3.4)	(5.5)
Other	**(10.0)**	(50.3)	4.6	1.6	5.9
Total retail sales (a)	**1.7**	(0.7)	0.5	(1.0)	0.1
Wholesale and contract sales	**4.2**	(9.7)	51.6	(0.8)	47.0
New England Power Pool	**(17.4)**	(53.7)	51.5	(33.5)	(9.8)
Total system	**1.0%**	(8.0)%	10.1%	(4.8)%	2.2%
Electric operating revenues by class:					
Commercial	**50%**	49%	48%	48%	49%
Residential	**28%**	28%	27%	27%	28%
Industrial	**9%**	10%	10%	10%	11%
Wholesale and contract	**11%**	12%	13%	13%	9%
Other	**2%**	1%	2%	2%	3%
Electric sales statistics:					
Residential averages:					
Annual kWh use	**6,197**	6,143	6,081	6,060	6,144
Revenue per kWh	**12.06¢**	11.62¢	10.80¢	10.66¢	10.18¢
Annual bill	**$749.47**	$ 709.89	$ 657.41	$ 641.62	$ 620.54
Customers:					
Average number	**655,707**	651,141	646,215	642,967	642,041

(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.

Certain reclassifications and re[illegible]ions were made to the data reported in prior years to conform with the method of presentation used in 1994.

Selected Consolidated Financial Statistics (Unaudited)

	1994	1993	1992	1991	1990
Operating revenues (000)	**$ 1,548,554**	$ 1,482,253	$ 1,411,753	$ 1,354,501	$ 1,314,440
Balance for common (000)	**$ 109,257**	$ 102,513	$ 90,748	$ 77,059	$ 77,788
Per common share:					
Earnings	**$ 2.41**	$ 2.28	$ 2.10	$ 1.96	$ 2.01[a]
Dividends declared	**$ 1.775**	$ 1.715	$ 1.655	$ 1.595	$ 1.535
Dividends paid	**$ 1.76**	$ 1.70	$ 1.64	$ 1.58	$ 1.52
Book value	**$ 20.11**	$ 19.42	$ 18.77	$ 17.92	$ 17.22
Operating cash flow [b]	**$ 8.12**	$ 6.58	$ 6.80	$ 5.50	$ 5.68
Payout ratio	**73%**	75%	78%	81%	76%
Return on average common equity	**12.1%**	11.9%	11.5%	11.3%	11.8%
Year-end dividend yield	**7.6%**	5.9%	6.2%	6.6%	7.9%
Fixed charge coverage (SEC)	**2.45**	2.22	1.89	1.8[illegible]	2.02
Capitalization:					
Total debt	**56%**	57%	56%	5[illegible]%	59%
Preferred and preference equity	**9%**	9%	9%	[illegible]0%	10%
Common equity	**35%**	34%	35%	32%	31%
Long-term debt (000)	**$ 1,136,617**	$ 1,272,497	$ 1,091,073	$ 1,136,765	$ 1,074,025
Mandatory redeemable preferred/ preference stock (000)	**$ 96,000**	$ 98,000	$ 98,000	$ 100,000	$ 100,000
Total assets (000)	**$ 3,616,610**	$ 3,477,288	$ 3,234,234	$ 3,119,285	$ 3,012,589
Internal generation after dividends (000)	**$ 216,305**	$ 193,484	$ 204,248	$ 193,019	$ 187,954
Plant and nuclear fuel expenditures (000)	**$ 220,694**	$ 253,254	$ 231,025	$ 214,213	$ 255,784
Internal generation	**98%**	76%	88%	90%	73%
Common shares outstanding:					
Weighted average	**45,337,661**	44,959,050	43,143,953	39,347,824	38,778,901
Year-end	**45,535,477**	45,129,227	44,763,055	42,047,356	38,998,531
Stock price - High	**29 7/8**	32 5/8	28 1/4	24 7/8	20 1/4
- Low	**21 1/2**	26 3/8	22 1/8	18 1/4	16 1/2
- Year-end	**24**	29 3/4	27 1/2	24 3/4	20
Year-end market value (000)	**$ 1,092,851**	$ 1,342,595	$ 1,230,984	$ 1,040,672	$ 779,971
Trading volume (shares)	**25,095,100**	18,729,400	26,460,900	17,464,300	19,652,300
Market/book ratio (year-end)	**1.19**	1.53	1.47	1.38	1.16
Price/earnings ratio (year-end)	**10.0**	13.0	13.1	12.6	10.0

(a) Includes $0.41 per common share from an accounting change.

(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 1994.

OFFICERS

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

George W. Davis, President and Chief Operating Officer

E. Thomas Boulette, Senior Vice President - Nuclear

Cameron H. Daley, Senior Vice President - Power Supply

L. Carl Gustin, Senior Vice President - Marketing & Corporate Relations

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

Ronald A. Ledgett, Senior Vice President - Power Delivery

Charles E. Peters, Jr., Senior Vice President - Finance

Alison Alden, Vice President - Sales & Service

Marc S. Alpert, Vice President and Treasurer

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

Douglas S. Horan, Vice President and General Counsel

Joel Y. Kamya, Vice President - Production Operations

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

Arthur P. Phillips, Jr., Vice President - Corporate Information Services

Robert A. Ruscitto, Vice President - Electric Customer Service

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

Theodora S. Convisser, Clerk of the Corporation

Donald Anastasia, Assistant Treasurer

James J. Judge, Assistant Treasurer and Director - Corporate Planning

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,c George W. Davis, President and Chief Operating Officer, Boston Edison Company

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

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

b,c,f Nelson S. Gifford, Former Vice Chairman, Avery Dennison Corporation (pressure-sensitive adhesives and materials, office products, product identification and control systems and specialty chemicals)

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 and Chief Executive Officer, Boston Edison Company

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

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

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

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

b,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

DIVIDEND REINVESTMENT PLAN

Our Dividend Reinvestment and Common Stock Purchase Plan (the plan) is available to our common and preferred stockholders. Under the plan, common and preferred stockholders may have their dividends reinvested in our common stock at current market prices. All participants may invest optional cash contributions, up to a maximum of $5,000 per quarter, which will be invested at the current market price. Participants do not pay fees or commissions.

All recordholders of shares of common and preferred stock are eligible to participate directly in the plan. 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 recordholder. If for any reason a beneficial owner is unable to arrange participation with their broker or bank nominee, they must become a recordholder by having the shares transferred to their own name.

All correspondence concerning changes in plan ownership should be directed to the plan agent:

The First National Bank of Boston
Dividend Reinvestment Unit
Mail Stop: 45-01-06
P. O. Box 1681
Boston, Massachusetts 02105-1681

IMPORTANT STOCKHOLDER INFORMATION

Annual Meeting

Our Annual Meeting of Stockholders will be held on May 12, 1995, at 11:00 a.m. If you wish to receive a copy of Tom May's remarks, please write to our Investor Relations Department at the General Offices address listed below.

Company Contact

Theodora Converse
Clerk of the Corporation

Investor Relations Contact

Phil Lembo
Director, Investor Relations

General Offices

800 Boylston Street, Boston, Massachusetts 02199-8003
(617) 424-2000

Stock Listings

New York and Boston stock exchanges

Stock Symbol

BSE

Dividend Payment Dates

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

Tax Status of 1994 Dividends

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

Stock Transfer Agent, Registrar of Stock and Dividend Reinvestment Plan Agent

The First National Bank of Boston

SEC Form 10-K

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

Quarterly Report to Shareholders

Beneficial owners of our stock whose shares are registered in names other than their own (e.g., a broker or bank nominee) may obtain copies of our Quarterly Reports to Shareholders on an ongoing basis by making a written request to our Investor Relations Department to be placed on their mailing list. Note that the Annual Report will continue to be mailed to beneficial owners directly by their bank or broker.

Inquiries Concerning Stock

If you have questions concerning your dividend payments, dividend direct deposit, dividend reinvestment plan status, transfer procedures or other stock account matters, please contact our Stock Transfer Agent at the following address:

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

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** or toll-free **1-800-736-3001**.

Boston Edison
Investor Relations P356
800 Boylston Street
Boston, Massachusetts 02199-8003

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[x] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 1995

or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from __________ to __________

Commission file number 1-2301

BOSTON EDISON COMPANY
(Exact name of registrant as specified in its charter)

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

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

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

Yes _____ No __x__

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

Class	Outstanding at September 30, 1995
Common Stock, $1 par value	47,890,445 shares

Part I - Financial Information
Item 1. Financial Statements

Boston Edison Company
Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 1995	December 31, 1994
Assets		
Utility plant in service, at original cost	$4,239,525	$4,074,810
Less: accumulated depreciation	1,430,307	1,344,452
	2,809,218	2,730,358
Nuclear fuel, net	56,331	55,597
Construction work in progress	82,357	144,048
Net utility plant	2,947,906	2,930,003
Investments in electric companies, at equity	23,717	24,678
Nuclear decommissioning trust	98,282	82,831
Current assets:		
Cash and cash equivalents	28,970	6,822
Accounts receivable	234,183	189,382
Accrued unbilled revenues	37,283	32,240
Fuel, materials and supplies, at average cost	62,872	71,560
Prepaid expenses and other	22,263	26,705
Total current assets	385,571	326,709
Regulatory assets:		
Redemption premiums	46,604	52,859
Income taxes, net	45,777	44,745
Power contracts	33,203	40,277
Pension and postretirement costs	16,645	22,761
Nuclear outage costs	15,778	17,804
Other	8,362	19,702
Total regulatory assets	166,369	198,148
Other deferred debits:		
Intangible asset - pension	33,184	22,849
Other	31,382	31,392
Total assets	$3,686,411	$3,616,610

The accompanying notes are an integral part of these financial statements.

Boston Edison Company
Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 1995	December 31, 1994
Capitalization and Liabilities		
Common stock equity:		
Common stock	$ 728,610	$ 668,338
Retained earnings	290,601	247,409
Total common stock equity	1,019,211	915,747
Cumulative preferred stock:		
Non-mandatory redeemable series	123,000	123,000
Mandatory redeemable series	92,000	94,000
Long-term debt	1,160,256	1,136,617
Current liabilities:		
Long-term debt/preferred stock due within one year	203,067	102,250
Notes payable	74,420	214,786
Accounts payable	84,155	139,119
Interest accrued	15,096	24,464
Dividends payable	24,582	23,533
Pension benefits	34,718	31,908
Other	109,296	76,615
Total current liabilities	545,334	612,675
Deferred credits:		
Power contracts	33,203	40,277
Accumulated deferred income taxes	507,762	515,454
Accumulated deferred investment tax credits	63,979	67,048
Nuclear decommissioning reserve	108,139	92,404
Other	33,527	19,388
Total deferred credits	746,610	734,571
Commitments and contingencies	-	-
Total capitalization and liabilities	$3,686,411	$3,616,610

The accompanying notes are an integral part of these financial statements.

Boston Edison Company
Consolidated Statements of Income
(Unaudited)
(in thousands, except per share amounts)

	Three Months Ended September 30, 1995	Three Months Ended September 30, 1994	Nine Months Ended September 30, 1995	Nine Months Ended September 30, 1994
Operating revenues	$500,179	$449,094	$1,265,794	$1,195,198
Operating expenses:				
Fuel	52,431	42,114	125,475	125,499
Purchased power	90,915	94,013	278,772	267,909
Other operations and maintenance	116,820	109,825	333,638	320,640
Depreciation and amortization	38,520	37,487	113,839	112,051
Amortization of deferred cost of cancelled nuclear unit	0	4,948	0	14,844
Amortization of deferred nuclear outage costs	12,765	1,930	16,625	5,791
Demand side management programs	15,223	9,405	39,646	27,451
Taxes - property and other	26,267	25,038	80,506	76,370
Income taxes	44,709	27,735	72,289	51,854
Total operating expenses	397,650	352,495	1,060,790	1,002,409
Operating income	102,529	96,599	205,004	192,789
Other income (expense), net	(342)	819	140	2,477
Operating and other income	102,187	97,418	205,144	195,266
Interest charges:				
Long-term debt	28,312	25,560	79,605	77,346
Other	2,692	3,934	11,665	9,182
Allowance for borrowed funds used during construction	(1,185)	(2,258)	(4,833)	(5,238)
Total interest charges	29,819	27,236	86,437	81,290
Net income	72,368	70,182	118,707	113,976
Preferred dividends provided	3,890	3,926	11,681	11,839
Balance available for common stock	$ 68,478	$ 66,256	$ 107,026	$ 102,137
Weighted average common shares outstanding	46,861	45,382	46,129	45,286
Earnings per share of common stock	$1.46	$1.46	$2.32	$2.26
Dividends declared per common share	$0.455	$0.440	$1.365	$1.320

The accompanying notes are an integral part of these financial statements.

Boston Edison Company
Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	Nine Months Ended September 30,	
	1995	1994
Operating activities:		
Net income	$118,707	$113,976
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	110,036	107,581
Amortization of nuclear fuel	13,279	16,738
Amortization of deferred cost of cancelled nuclear unit, net	0	14,301
Amortization of deferred nuclear outage costs	16,625	5,791
Other amortization	11,975	11,000
Deferred income taxes	(8,991)	12,114
Investment tax credits	(3,069)	(3,055)
Allowance for borrowed funds used during construction	(4,833)	(5,238)
Net changes in:		
Accounts receivable and accrued unbilled revenues	(49,844)	(36,188)
Fuel, materials and supplies	5,143	2,045
Accounts payable	(54,964)	(20,486)
Other current assets and liabilities	31,614	21,504
Other, net	19,386	19,488
Net cash provided by operating activities	205,064	259,571
Investing activities:		
Plant expenditures (excluding AFUDC)	(125,468)	(124,370)
Nuclear fuel expenditures	(12,298)	(9,956)
Capitalized demand side management expenditures	0	(15,325)
Nuclear decommissioning trust investments	(15,451)	(11,750)
Electric company investments	961	(205)
Net cash used by investing activities	(152,256)	(161,606)
Financing activities:		
Issuances:		
Common stock	61,773	7,978
Long-term debt	125,000	15,000
Redemptions:		
Preferred stock	(2,000)	(2,000)
Long-term debt	(600)	(28,600)
Net change in notes payable	(140,366)	(22,237)
Dividends paid	(74,467)	(71,549)
Net cash used by financing activities	(30,660)	(101,408)
Increase/(decrease) in cash and cash equivalents	22,148	(3,443)
Cash and cash equivalents at beginning of year	6,822	8,768
Cash and cash equivalents at end of period	$ 28,970	$ 5,325
Cash paid during the period for:		
Interest	$100,638	$99,944
Less: amounts capitalized	4,833	5,238
	$ 95,805	$94,706
Income taxes	$ 63,177	$28,690

The accompanying notes are an integral part of these financial statements.

Notes to Consolidated Financial Statements

A) Basis of Presentation

The accompanying unaudited consolidated financial statements should be read in conjunction with the Boston Edison Company (the Company) 1994 Form 10-K Annual Report and Forms 10-Q for the periods ended March 31, 1995 and June 30, 1995. In the opinion of the Company, the accompanying unaudited consolidated financial statements reflect all adjustments (which are all of a normal recurring nature, except for the amortization of deferred nuclear outage costs as described in Note B) necessary to present fairly the financial position as of September 30, 1995 and the results of operations for the three and nine months ended September 30, 1995 and 1994 and the cash flows for the nine months ended September 30, 1995 and 1994. Certain reclassifications have been made to the prior year data to conform to the current presentation.

The results of operations for the three and nine months ended September 30, 1995 are not indicative of the results which may be expected for the entire year. 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 Massachusetts Department of Public Utilities (DPU). Accordingly, greater than half of the Company's annual earnings typically occurs in the third quarter.

B) Deferred Nuclear Outage Costs

In the third quarter of 1995 the Company changed the amortization period of deferred nuclear outage costs to two 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 per 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. The Company 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 were written off. Approximately $15 million of deferred costs from the 1995 refueling outage are being amortized over two years.

C) Commitments and Contingencies

In 1991 the Company was named in a lawsuit 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 defend this case vigorously. Based on the information presently available, the Company does not expect that this litigation or certain other legal matters in which the Company is currently involved will have a material impact on its financial condition. However, an unfavorable decision ordered against the Company could have a material impact on the results of a reporting period.

The Company currently owns or operates 43 specific properties where hazardous materials were released in the past. The Company is required to clean up these properties in accordance with a timetable developed by the Massachusetts

Department of Environmental Protection and is 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. The Company also continues to face possible liability as a potentially responsible party in the cleanup of eight 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. At the majority of these sites the Company is one of many potentially responsible parties and currently expects to have only a small percentage of the potential liability. Through September 30, 1995, the Company has accrued approximately $7 million related to its cleanup liabilities. The Company is unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount, although based on its assessments of the specific site circumstances, it does not expect any such additional costs to have a material impact on its financial condition. However, additional provisions for cleanup costs could have a material impact on the results of a reporting period.

D) Corporate Reorganization

In July 1995 the Company announced a corporate reorganization into four separate business units effective November 1, 1995: Customer, Generating-Fossil, Generating-Nuclear and Corporate Services. As part of this reorganization, the Company intends to reduce its workforce by approximately 450 employees by the end of 1996. Part of this reduction will be achieved through a voluntary retirement incentive. The Company announced voluntary enhanced retirement programs for all employees who are at least 55 years old with varying years of service requirements for management and union employees. Approximately 600 employees are eligible for the programs, which are available until early December. A majority of the eligible employees are expected to participate in the programs. The Company will incur a one-time charge to fourth quarter earnings as a result of the programs; the charge will be determined by the number of employees that accept the offer.

Approximately 70 of the Company's upper and middle management positions and related administrative support positions will be eliminated by the end of 1995 regardless of the results of the enhanced retirement programs. A special severance program was announced for these affected employees who are not eligible for or do not accept the enhanced retirement program, which resulted in a one-time, pre-tax charge to third quarter earnings of $7 million. The total of the $7 million third quarter charge and the fourth quarter charge to be incurred from the enhanced retirement programs is estimated to be approximately $25 million on a pre-tax basis. Depending on the level of participation, the charge could be higher or lower. The Company is currently evaluating its options in order to achieve the 450 employee reduction if it is not achieved through the enhanced retirement program and the management and administrative support reduction.

E) Income Taxes

The following table reconciles the federal statutory income tax rate to the annual estimated effective income tax rate for 1995 and the actual effective income tax rate for 1994.

	1995	1994
Statutory tax rate	35.0%	35.0%
State income tax, net of federal income tax benefit	4.3	4.3
Investment tax credits	(2.0)	(2.3)
Reversal of deferred taxes - settlement agreement	-	(5.5)
Other	0.5	(0.1)
Effective tax rate	37.8%	31.4%

F) Long-Term Securities

On September 29, 1995, the Company sold one million shares of common stock with net proceeds of $26 million to Merrill Lynch & Co. as underwriters for a public offering. The proceeds, which are included in the cash balance at September 30, were used to reduce short-term debt in early October.

Item 2. Management's Discussion and Analysis

Results of Operations - Three Months ended September 30, 1995 vs. Three Months ended September 30, 1994

Earnings per common share amounted to $1.46 for both the three months ended September 30, 1995 and 1994. Third quarter earnings in 1995 include a one-time charge of $0.09 per share for severance benefits relating to the Company's restructuring, which is discussed in the outlook for the future section. Excluding the one-time charge, earnings increased due to a $29 million annual retail base rate increase effective November 1994, lower revenue reserves and the ending of amortization of deferred cancelled nuclear costs in 1994. These positive changes were partially offset by higher amortization of deferred nuclear outage costs and income tax expense.

The results of operations for the quarter are not indicative of the results which may be expected for the entire year due to the seasonality of the Company's kWh sales and revenues. Refer to Note A to the consolidated financial statements.

Operating revenues

Operating revenues increased 11.4% in the third quarter of 1995 as follows:

(in thousands)	
Retail electric revenues	$26,488
Demand side management revenues	9,173
Wholesale and other revenues	11,157
Short-term sales revenues	4,267
Increase in operating revenues	$51,085

Retail electric revenues increased $26.5 million. The November 1994 base rate increase resulted in approximately $17 million of the increased revenues and approximately $4 million was due to a 2.3% increase in retail kWh sales. Performance revenues, which vary annually based on the operating performance of Pilgrim Nuclear Power Station, increased approximately $5 million mainly as a result of an outage that occurred at the station in 1994.

A new annual conservation charge for recovery of demand side management (DSM) program costs was implemented in February 1995. Under this current charge substantially all 1995 program costs are recovered in the current year. This results 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 $10 million of revenue reserves recorded in 1994 mainly related to potential customer contract issues.

Increased short-term sales revenues are the result of higher Company generating availability in 1995. Revenues from short-term sales serve to reduce fuel and purchased power billings to retail customers and therefore have no effect on earnings.

Operating expenses

Total fuel and purchased power expenses increased $7 million due to the timing effect of fuel and purchased power cost collection. In addition to the timing effect, fuel expense increased despite lower fossil fuel prices primarily due to a 41% increase in Company generation, while purchased power expense decreased due to a 28% decrease in kWh purchases. Fuel and purchased power expenses are substantially all recoverable through fuel and purchased power revenues.

The increase in other operations and maintenance expense is due to a $7 million one-time charge for severance benefits. Refer to the outlook for the future section for more information regarding the severance program related to the Company's restructuring.

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

The 1995 amortization of deferred nuclear outage costs reflects a change in the amortization period to two 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 were written off. Approximately $15 million of deferred costs from the 1995 refueling outage are 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.

Property and other taxes increased due to higher property taxes imposed by a majority of the municipalities in which the Company operates.

The Company's estimated effective annual income tax rate for 1995 is 37.8% versus an actual rate of 31.4% for 1994. The higher rate is the result of a $10 million adjustment to deferred income taxes in 1994 made in accordance with the Company's 1992 settlement agreement.

Interest charges

Interest charges on long-term debt increased primarily due to a $125 million debentures issuance in May 1995. Other interest charges decreased due to a lower average short-term debt level partially offset by higher short-term interest rates. The allowance for borrowed funds used during construction (AFUDC) decreased due to a lower construction work in progress balance partially offset by a higher AFUDC rate related to the higher short-term interest rates.

Results of Operations - Nine Months ended September 30, 1995 vs. Nine Months ended September 30, 1994

Earnings per common share for the nine months ended September 30, 1995 amounted to $2.32 as compared to $2.26 per common share for the nine months ended September 30, 1994. The increase in earnings is primarily due to the $29 million base rate increase effective November 1994, the ending of amortization of deferred cancelled nuclear costs in 1994 and lower revenue reserves. These positive changes were partially offset by higher amortization of deferred nuclear outage costs and higher operations and maintenance, property tax, income tax and interest expenses.

The results of operations for the nine months ended September 30, 1995 are not indicative of the results which may be expected for the entire year due to the seasonality of the Company's kWh sales and revenues. Refer to Note A to the consolidated financial statements.

Operating revenues

Operating revenues increased 5.9% in the first nine months of 1995 as follows:

(in thousands)	
Retail electric revenues	$39,578
Demand side management revenues	13,880
Wholesale and other revenues	18,234
Short-term sales revenues	(1,096)
Increase in operating revenues	$70,596

Retail electric revenues increased $39.6 million. The November 1994 base rate increase resulted in approximately $27 million of the increase. Fuel and purchased power revenues increased approximately $9 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 effect on earnings. Performance revenues increased $4 million primarily due to a higher rate effective in the performance year ended October 1995 and an outage that occurred at the station in 1994.

A new annual conservation charge for recovery of demand side management program costs was implemented in February 1995, resulting in higher DSM revenues and expenses, as discussed in the results of operations for the third quarter.

The net increase in wholesale and other revenues is primarily due to a $14 million decrease in revenue reserves. In 1994 $16 million of reserves were recorded primarily related to certain wholesale and contract customers. The August 1994 acquisition of Coneco Corporation also provided an additional $4 million of revenues in 1995.

Operating expenses

Total fuel and purchased power expenses increased $11 million primarily due to the timing effect of fuel and purchased power cost collection. The increase in fuel expense due to the timing effect and a 9% increase in fossil station output was offset by lower fossil fuel prices and a 10% decrease in nuclear generation.

Other operations and maintenance expense increased 4% due to the $7 million one-time charge for severance benefits in the third quarter and increases in employee benefit expenses. Subsidiary operation expenses also increased due to the Coneco Corporation acquisition.

The increase in amortization of deferred nuclear outage costs reflects a change in the amortization period to two from five years as discussed in the results of operations for the third quarter.

The increase in demand side management programs expense is related to the increase in DSM revenues. Both revenues and expenses are higher due to the 1995 change in DSM recovery timing that results in the current year recovery and expense recognition of program costs.

The Company's estimated effective annual income tax rate for 1995 is 37.8% versus an actual rate of 31.4% for 1994 as discussed in the results of operations for the third quarter.

Interest charges

Interest charges on long-term debt increased due to the $125 million debentures issuance in May 1995 partially offset by debentures and first mortgage bond redemptions in 1994. Other interest charges increased due to higher short-term interest rates partially offset by a lower average short-term debt level.

Financial Condition

The Company's 1992 settlement agreement with the DPU limits the annual rate of return on equity during 1995 to 11.75%, excluding any penalties or rewards from performance incentives. The Company's ability to achieve or exceed the 11.75% rate of return on equity is primarily dependent upon its ability to control costs and to earn performance incentives, primarily based on Pilgrim Station's annual capacity factor. The capacity factor for the recently concluded performance year ended October 1995 was 67%.

The Company does not plan to make a base rate filing following the expiration of the 1992 settlement agreement and therefore anticipates base rates to remain in effect at their current levels. However, as discussed in the outlook for the future section, the Company is required to file a plan with the DPU in February 1996 based on the recent industry restructuring order. It is uncertain how and when the filing and subsequent negotiations and industry changes will impact the Company's rates.

Liquidity

The Company supplements internally generated funds with external financings, primarily through the issuance of short-term commercial paper and bank borrowings. The Company has authority from the Federal Energy Regulatory Commission (FERC) to issue up to $350 million of short-term debt. The Company has 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 September 30, 1995 the Company had $74 million of short-term debt outstanding, none of which was incurred under the revolving credit agreement. 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. See Note F to the consolidated financial statements for specific information relating to recent financing activities.

Outlook for the Future

A significant portion of the Company's electricity sales is made to commercial customers rather than industrial customers. As a result the Company's sales have been only moderately impacted by unfavorable economic factors affecting the manufacturing industry in Massachusetts and have been positively impacted by economic growth in the commercial sector. Retail electricity sales decreased 0.4% in the first nine months of 1995 primarily due to mild winter weather conditions compared to extremely cold weather conditions in 1994.

The DPU is currently investigating whether the Company should again be ordered to negotiate a contract to purchase power from an independent power producer, JMC Altresco, Inc. The investigation is in response to the Massachusetts Supreme Judicial Court's (SJC) decision remanding the DPU's previous order due to its failure to evaluate the cost of the project to customers. The Company filed a motion to dismiss the matter, but also filed testimony comparing the cost of Altresco to projected market costs and hearings are currently ongoing. In a separate but related matter, the Company supported an appeal filed by other parties of the Massachusetts Energy Facilities Siting Board's (EFSB) conditional approval of construction of Altresco's generating station project. In January 1995 the SJC reversed and remanded the EFSB's approval on the basis that there was no showing of need for the project in Massachusetts prior to 2000. In August 1995 the EFSB issued a subsequent approval for the Altresco project with an in-service date of 1998 finding that the project would provide a necessary energy supply for Massachusetts. The Company appealed the August approval to the SJC based on the denial of the Company's petition to intervene and the EFSB's failure to consider current market information and forecasts.

In July 1995 the Company announced a corporate reorganization as discussed in Note D to the consolidated financial statements. In order to achieve a workforce reduction of approximately 450 employees by the end of 1996, the Company offered enhanced retirement programs and is eliminating certain management and support positions. The Company will incur a one-time charge to fourth quarter earnings as a result of the enhanced retirement programs; the charge will be determined by the number of employees that accept the offer. A special severance program announced for affected employees who are not eligible for or do not accept the enhanced retirement programs resulted in a one-time, pre-tax charge to third quarter earnings of $7 million. The total of the $7 million third quarter charge and the fourth quarter retirement programs charge is estimated to be approximately $25 million on a pre-tax basis. Depending on the level of participation, the charge could be higher or lower. The Company is currently evaluating its options in order to achieve the 450 employee reduction if it is not achieved through the enhanced retirement programs and the management and administrative support reduction. The Company anticipates ongoing savings as a result of the reorganization.

On August 16, 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 permit more competition for customers. It includes principles for a restructured electric industry that consist of customer choice and the benefits of competition for all customers;

full competition in generation markets; functionally separate generation, transmission and distribution services; universal service; support for environmental regulation goals; and incentive regulation for the transmission and distribution of electricity, which remain monopoly services. The DPU's order also set 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; and ensure an orderly and quick transition which minimizes customer confusion. The order allows a reasonable opportunity for the recovery of net, non-mitigable potentially strandable costs, over a period of five 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. The procedure and criteria for recovering potentially strandable costs are uncertain, and the extent of the Company's ability to recover all or part of its potentially strandable costs is unknown at this time.

The order established only general principles for the transition to a competitive market and did not establish a particular model for the new industry structure. The order requires each of the Massachusetts-based electric utilities to develop a plan for moving toward competition consistent with the DPU's order and encourages utilities to negotiate with all interested parties while doing so. The Company is one of three companies required to file a restructuring plan by February 16, 1996.

Part II - Other Information

Item 5. Other Information

The following additional information is furnished in connection with the Registration Statement on Form S-3 of the Registrant (File No. 33-57840), filed with the Securities and Exchange Commission on February 3, 1993.

Price and dividend information per share of common stock:

	Price		Dividend
	High	Low	Paid
First quarter 1995	$25 1/2	$23 1/8	$0.455
Second quarter 1995	27	23 3/8	0.455
Third quarter 1995	27 1/2	24 1/2	0.455

The last sales price of the Company's common stock on the New York Stock Exchange as reported in the *Wall Street Journal* for November 9, 1995 was $27 3/8 per share.

Ratio of earnings to fixed charges and ratio of earnings to fixed charges and preferred stock dividend requirements:

Twelve months ended September 30, 1995:

Ratio of earnings to fixed charges	2.59
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.18

Item 6. Exhibits and Reports on Form 8-K

a) Exhibits filed herewith:

Exhibit 12 - Computation of ratio of earnings to fixed charges

12.1 - Computation of ratio of earnings to fixed charges for the twelve months ended September 30, 1995

12.2 - Computation of ratio of earnings to fixed charges and preferred stock dividend requirements for the twelve months ended September 30, 1995

Exhibit 15 - Letter re unaudited interim financial information

15.1 - Report of Independent Accountants

Exhibit 27 - Financial Data Schedule

27.1 - Schedule UT

Exhibit 99 - Additional Exhibits

99.1 - Letter of Independent Accountants

Re Form S-3 Registration Statements filed by the Company on September 14, 1990 (File No. 33-36824), February 3, 1993 (File No. 33-57840) and May 31, 1995 (File No. 33-59693); 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)

b) No Form 8-K was filed during the third quarter of 1995.

Signature

Pursuant to the requirements 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
(Registrant)

Date: November 13, 1995

/s/ Robert J. Weafer, Jr.
Robert J. Weafer, Jr.
Vice President, Controller and Chief Accounting Officer

Exhibit 12.1

Boston Edison Company
Computation of Ratio of Earnings to Fixed Charges
Twelve Months Ended September 30, 1995
(in thousands)

Net income from continuing operations	$129,753
Income taxes	76,864
Fixed charges	129,701
Total	$336,318
Interest expense	$119,679
Interest component of rentals	10,022
Total	$129,701
Ratio of earnings to fixed charges	2.59

Exhibit 12.2

Boston Edison Company
Computation of Ratio of Earnings to Fixed Charges
and Preferred Stock Dividend Requirements
Twelve Months Ended September 30, 1995
(in thousands)

Net income from continuing operations	$129,753
Income taxes	76,864
Fixed charges	129,701
Total	$336,318
Interest expense	$119,679
Interest component of rentals	10,022
Subtotal	129,701
Preferred stock dividend requirements	24,503
Total	$154,204
Ratio of earnings to fixed charges and preferred stock dividend requirements	2.18

Exhibit 15.1

Report of Independent Accountants

To the Stockholders and Directors
of Boston Edison Company

We have reviewed the accompanying consolidated balance sheet of Boston Edison Company (the Company) and subsidiaries as of September 30, 1995 and the related statements of income for the three and nine-month periods ended September 30, 1995 and 1994 and statements of cash flows for the nine-month periods ended September 30, 1995 and 1994. These financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures to financial data and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying financial statements in order for them to be in conformity with generally accepted accounting principles.

Boston, Massachusetts
October 26, 1995

COOPERS & LYBRAND L.L.P.

Exhibit 99.1

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Boston Edison Company
Registration on Form
S-3 and Form S-8

We are aware that our report dated October 26, 1995 on our review of the interim financial information of Boston Edison Company for the period ended September 30, 1995 and included in this Form 10-Q is incorporated by reference in the Company's registration statements on Form S-3 (File Nos. 33-36824, 33-57840 and 33-59693) and on Form S-8 (File Nos. 33-00810, 33-7558, 33-38434, 33-48424, 33-48425, 33-59662, 33-59682 and 33-58457). Pursuant to Rule 436(c) under the Securities Act of 1933, this report should not be considered a part of the registration statements prepared or certified by us within the meaning of Sections 7 and 11 of that Act.

Boston, Massachusetts
October 26, 1995

COOPERS & LYBRAND L.L.P.

BOSTON EDISON COMPANY

1995 INTERNAL CASH FLOW PROJECTION
FOR PILGRIM UNIT #1 NUCLEAR POWER STATION
(DOLLARS IN THOUSANDS)

	12 Months Ended 9/30/95	Projected Year 1996
Net Income After Taxes	$129,753	$141,000
Less Dividends Paid	(98,378)	(108,000)
Retained Earnings	31,375	33,000
Adjustments:		
Depreciation and Amortization	180,446	260,000
Depreciation Nuclear Outage Costs	18,556	(8,000)
Deferred Taxes and ITC	(29,395)	(38,000)
AFUDC	(7,073)	(4,000)
Total Adjustments	$162,534	$210,000
Internal Cash Flow	$193,909	$243,000
Average Quarterly Cash Flow	$48,477	$60,750
Percentage Ownership in All Operating Nuclear Units	Pilgrim Unit #1	74%
Maximum total Contingency Liability		$10,000

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ITEM (4) NARRATIVE STATEMENTS OF CURTAILMENT OF CAPITAL EXPENDITURES:

The Boston Edison Company would be able to curtail $10 million of capital expenditures within any three month period of the next twelve months if it becomes necessary to pay retrospective premiums.