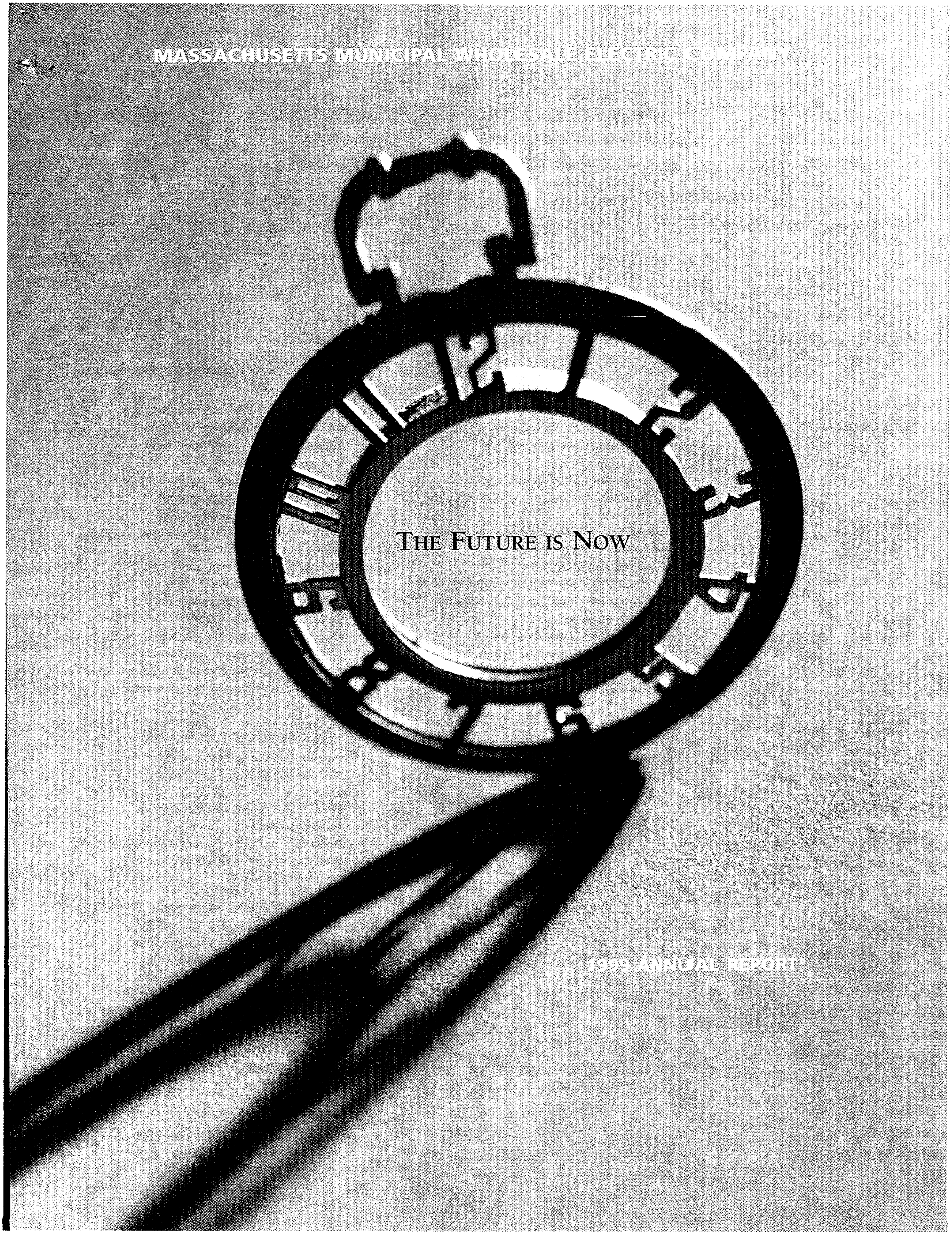

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
THE FUTURE IS NOW
1999 ANNUAL REPORT

The Massachusetts Municipal Wholesale Electric Company (MMWEC) is a non-profit, public corporation and political subdivision of the Commonwealth of Massachusetts, created under Chapter 775 of the Acts of 1975. MMWEC is the Joint Action Agency for the consumer-owned municipal utilities of Massachusetts, providing a variety of power supply, financial and other energy services to its 22 member and 35 project participant utilities, as well as other utilities. MMWEC also is the principle owner and operator of the Stony Brook Power Plant, a 520-megawatt, combined-cycle intermediate and peaking plant located in Ludlow, MA.

MMWEC Member Utilities

Ashburnham Municipal Light Plant
Belmont Municipal Light Department
Boylston Municipal Light Department
Concord Municipal Light Plant
Danvers Electric Division
Groton Electric Light Department
Hingham Municipal Lighting Plant
Holden Municipal Light Department
Holyoke Gas and Electric Department
Hull Municipal Lighting Plant
Ipswich Municipal Light Department
Mansfield Municipal Electric Department
Marblehead Municipal Light Department
Middleton Municipal Light Department
Paxton Municipal Light Department
Rowley Municipal Lighting Plant
Shrewsbury's Electric Light Plant
Sterling Municipal Light Department
Templeton Municipal Lighting Plant
Wakefield Municipal Gas and Light Department
West Boylston Municipal Lighting Plant
Westfield Gas and Electric Light Department

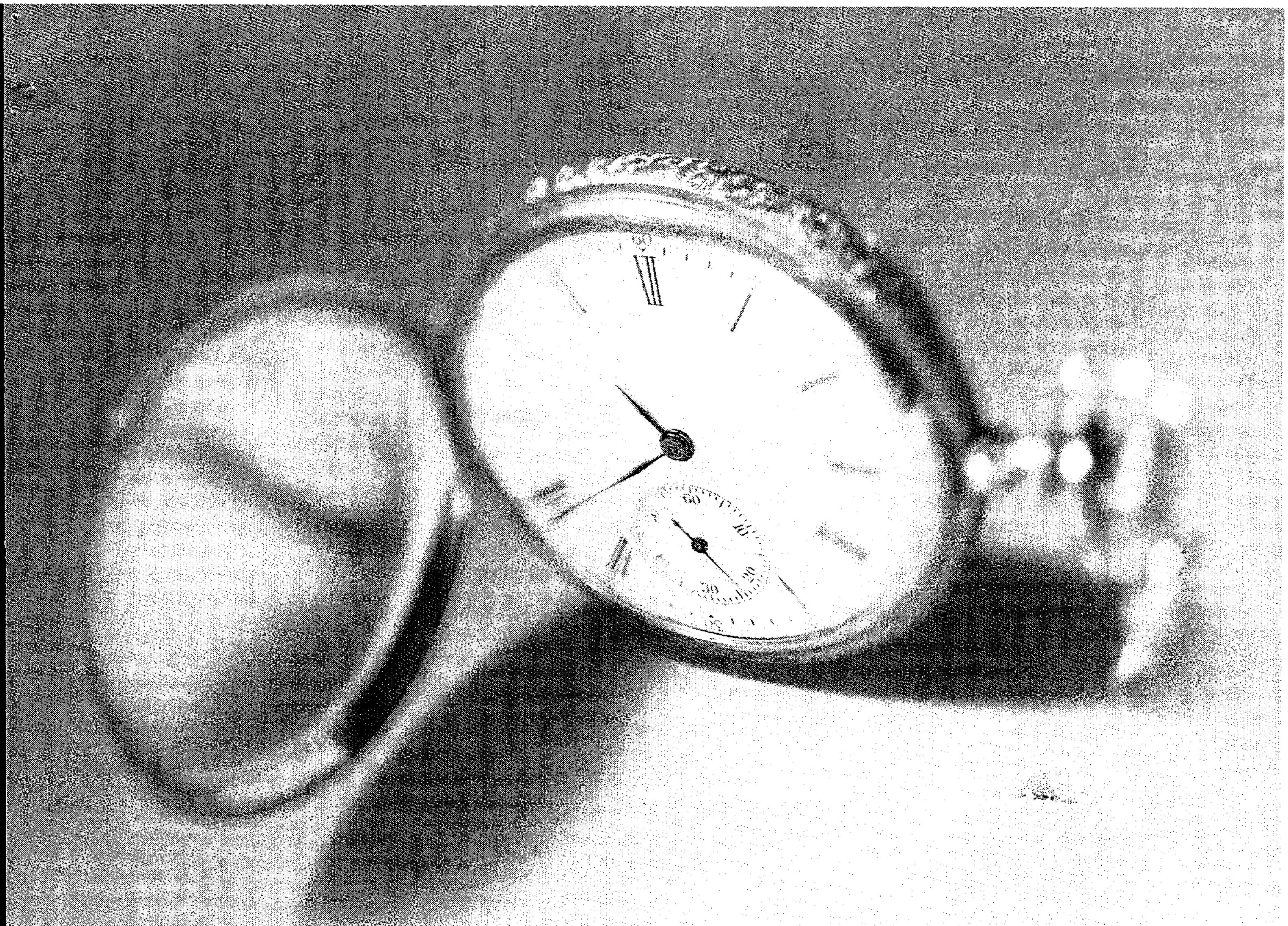
MMWEC Power Supply Project Participants

(Massachusetts)

Ashburnham Municipal Light Plant
Boylston Municipal Light Department
Braintree Electric Light Department
Danvers Electric Division
Georgetown Municipal Light Department
Groton Electric Light Department
Hingham Municipal Lighting Plant
Holden Municipal Light Department
Holyoke Gas and Electric Department
Hudson Light and Power Department
Hull Municipal Lighting Plant
Ipswich Municipal Light Department
Littleton Electric Light & Water Department
Mansfield Municipal Electric Department
Marblehead Municipal Light Department
Middleborough Gas and Electric Department
Middleton Municipal Light Department
North Attleborough Electric
Paxton Municipal Light Department
Peabody Municipal Light Plant
Reading Municipal Light Department
Shrewsbury's Electric Light Plant
South Hadley Electric Light Department
Sterling Municipal Light Department
Templeton Municipal Lighting Plant
Wakefield Municipal Gas and Light Department
West Boylston Municipal Lighting Plant
Westfield Gas and Electric Light Department

(Out-of-State Power Supply Project Participants)

Pascoag Fire District (RI)
Green Mountain Power Corporation (VT)
Hardwick Electric Department (VT)
Village of Ludlow Electric Light Department (VT)
Stowe Electric Department (VT)
Swanton Village Electric Department (VT)
Village of Morrisville Water and Light Department (VT)

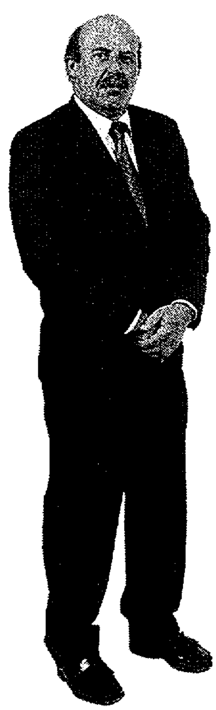


A Letter From Management

MMWEC and its member utilities are stronger and better positioned to succeed due to a number of important accomplishments over the past year. We have assisted in the buyout of high-cost power contracts, improving the financial condition of many municipal utilities. We have implemented a successful all-requirements power supply program, enabling municipal utilities to participate effectively in a changing marketplace. We are implementing key parts of a new strategic plan that focuses on enhancing the competitiveness of member utilities. And, among other things, we have a much stronger position within the New England Power Pool (NEPOOL), which is developing rules for the region's newly competitive wholesale power markets.

MMWEC has been successful in these and other areas for two basic reasons. First, in all that it does, the MMWEC organization is driven by the enduring values of public power, including consumer ownership, local control, superior service and non-profit operation. These time-tested values, and the entities guided by them, are earning a growing level of respect and recognition in the debates that are shaping the future of the electric industry. As it has so many times in the past, public power is emerging as the voice of reason in the rush to establish competitive power markets, with a focus on ensuring that competition achieves its intended goal of reducing costs for consumers. This broadening appeal of public power's message and core values bodes well for MMWEC and public power in Massachusetts.

Secondly, MMWEC recognizes that the future of the electric industry is now, and we are intensely focused on seizing the opportunities of each new day. More literally than ever before in this industry, tomorrow's opportunities spring from today's accomplishments. The number and scope of issues are expanding; the pace of change is accelerating; and the future of MMWEC is a work in progress that is based largely on today's achievements. By building on the previous day's work, MMWEC is using each day to advance the interests of public power and create new opportunities for its members. This reality may be most evident in negotiations related to the restructuring of NEPOOL, where the vast number of issues and tight regulatory deadlines require swift decision-making. Each decision becomes part of the foundation for subsequent proposals, and the benefits of effective participation are compounded with the adoption of each new rule.



H. Bradford White
Director and
Chairman of The Board

The text in this year's annual report includes a built-in timeline to convey this sense of compounding achievement experienced by MMWEC over the past year. One of the most important developments is the establishment of an all-requirements power supply program, under which municipal utilities can pool their electric needs and resources through MMWEC to achieve greater efficiency and economy in wholesale power markets. After operating for several months on a trial basis, the all-requirements program was officially launched in May to coincide with the startup of NEPOOL's competitive power markets. MMWEC's successful participation in these Internet-based markets has required an ongoing commitment to improving computer systems and software, as well as a commitment to the training and education of staff and member utilities.

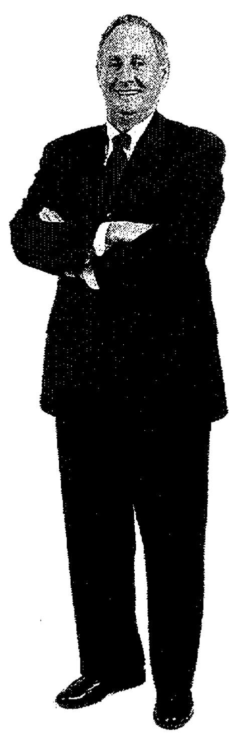
Looking back on a year of NEPOOL restructuring, the most significant event involved an overhaul of NEPOOL's governance structure that gave a new public power sector up to 25 percent of the NEPOOL vote, compared to about 7.5 percent under the old structure. This dramatic shift in control in favor of public power represents a huge step forward for MMWEC, which currently votes the majority of the public power share as the alternate or proxy for many public power systems. Now, at a key point in the NEPOOL restructuring process, public power has sufficient strength to sway the vote on many issues. This new arrangement is immensely significant, giving MMWEC and public power a strong voice within NEPOOL and establishing a precedent for effective public power participation and consumer representation in any new regional groups established to govern the operation of electric power systems.

In another case of compounding benefit, the savings resulting from the buyout of high-cost power contracts more than quadrupled for municipal utilities in 1999, to an estimated $34 million. Building upon its initial contract buyout in 1998, MMWEC expanded its tax-exempt commercial paper borrowing program to finance the buyout of two additional above-market power contracts. Disposal of such above-market assets, also referred to as stranded costs, improves the financial position of municipal utilities and better prepares them to face competitive challenges.

Helping members capitalize on opportunities resulting from competition and industry restructuring also is the overall objective of MMWEC's new strategic plan. In a planning process that began early last year, MMWEC has assessed its strengths, weaknesses and market opportunities; analyzed municipal utility needs; and identified a number of alternative roles in which MMWEC could support and meet the needs of its members. Selected elements of this multifaceted plan are scheduled for action in 2000, with implementation continuing over the next several years.

Working closely with its members and project participants, MMWEC also has developed a plan to refund all of its outstanding long-term debt and restructure its General Bond Resolution. While these actions would give MMWEC greater flexibility in managing its assets, an alternate, more traditional debt refunding plan also could produce significant savings for participants. MMWEC has carefully positioned itself to carry out either of these financing strategies, depending on bond market conditions and other factors.

Inside this report you'll find more information on MMWEC's recent achievements and ongoing initiatives. The diverse work of the MMWEC organization, as reflected in these pages, requires a broad range of professional talent and expertise. MMWEC is fortunate to have a staff of highly skilled and dedicated professionals who are deeply committed to the consumers served by public power. Working together with the MMWEC members, project participants and other consumer-owned utilities, MMWEC is building a positive future for municipal utilities in Massachusetts, day by day.



George E. Leary
General Manager and Secretary

H. Bradford White
Director and Chairman of the Board

George E. Leary
General Manager and Secretary

JANUARY

• MMWEC Membership Meeting: Staff discusses power services designed for effective municipal participation in wholesale markets, including all-requirements power supply program.

At an MMWEC Membership Meeting, staff discussed efforts to ensure effective municipal utility participation in New England's restructured wholesale power markets, which began operating on May 1, 1999.

These efforts have included tighter integration of MMWEC's power supply functions and the establishment of a risk management team. By closely coordinating its fuel purchasing, power brokering, plant bidding and other power supply functions, MMWEC has been able to optimize its members' power supplies in the new wholesale markets and keep power costs as low as possible.

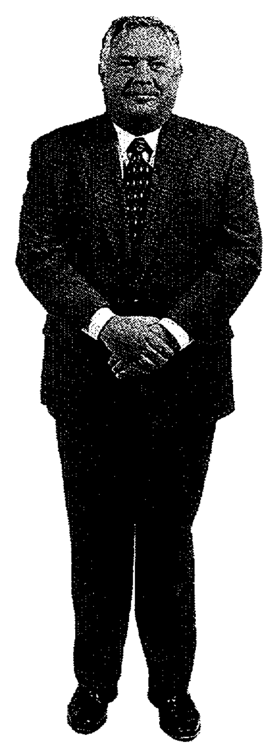
Higher levels of risk associated with the new markets are being identified and addressed by the risk management team, which includes individuals with expertise in finance, plant operations and power supply planning.

A key service offered by MMWEC is its all-requirements power supply program, under which municipal utilities pool their electric loads and resources through MMWEC to achieve greater efficiency and economy in the wholesale markets. With 10 all-requirements participants early in 2000, this program, among other things, enables municipal utilities to focus on distribution services while MMWEC handles the complexities of participating in competitive markets.

As part of its new strategic plan, MMWEC is developing three alternative service agreements to replace the current single service agreement that all members must sign. The new service agreements are being structured to accommodate the different service requirements of municipal utilities, giving current and potential future MMWEC members more choices and more flexible service options.

• MMWEC receives an $816,810 tax abatement from the Town of Seabrook, NH as part of a settlement resolving challenges by MMWEC and others to the assessed value of Seabrook Station. MMWEC owns 11.59 percent of Seabrook Station.

• MMWEC's short-term power brokering program surpasses $15 million in savings for program participants.



Daniel Golubek
MMWEC Director and Manager of the Westfield Municipal Gas and Electric Light Department

FEBRUARY

• Representatives of MMWEC attend American Public Power Association (APPA) legislative rally in Washington, D.C. and meet with elected officials to support tax-exempt financing and address other issues of concern.

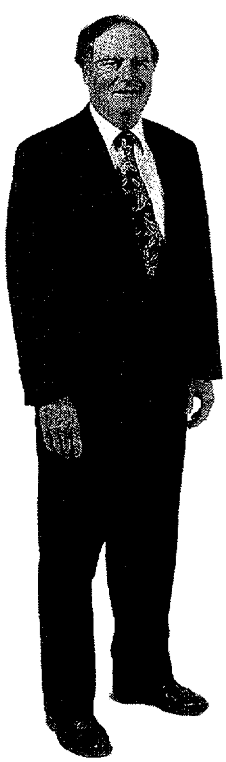
With the U.S. Congress considering electric industry restructuring issues, MMWEC stepped up its federal legislative activities in the past year.

During three separate visits to Washington, D.C., MMWEC representatives met with key legislators to discuss a variety of restructuring issues. Then and in follow-up contacts, MMWEC emphasized the need for passage of the Bond Fairness and Protection Act, which eases the private use restrictions of federal tax law, enabling municipal utilities with tax-exempt debt to participate more effectively in competitive power markets.

Early in 2000, MMWEC was organizing a legislative campaign to protect the rights of Massachusetts municipal utilities to inexpensive hydroelectric power from New York's federal hydropower projects.

• MMWEC staff works with individual member utilities to enhance their Internet, e-mail and other on-line capabilities.

• Board authorizes staff to proceed with L'Energia contract buyout.



William J. Wallace
MMWEC Director
and Manager of the
Wakefield Municipal
Gas and Light Department

The buyout and termination of the 7.6-megawatt L'Energia contract, which was completed late in May, was part of a continuing effort on the part of MMWEC and its members to reduce their above-market, or stranded, power costs. So far, the MMWEC municipal utilities have reduced such costs by more than $34 million through a series of contract buyouts.

MMWEC initiated its contract buyout activities in 1998 with the termination of an 11.5-megawatt contract with Refuse Fuels Associates (RFA). Because the cost of power under this contract was significantly above market prices, the 17 municipal contract participants will save more than $8 million after paying contract termination costs and purchasing replacement power at market prices.

While the amount of savings varied, the economics of MMWEC's subsequent contract buyouts worked the same way. Buyout of the L'Energia contract will yield more than $8.3 million in savings for three municipal utilities, and the buyout of their Pilgrim nuclear plant contracts will save 13 municipals an estimated $18 million.

To finance these contract buyouts, MMWEC created and implemented a tax-exempt, commercial paper financing program that has been very successful. After issuing more than $22 million in commercial paper notes to finance the RFA contract buyout, MMWEC expanded the financing program to accommodate the potential buyouts of other contracts. Consistent with this expansion, in June 1999 MMWEC obtained authorization from the state Department of Telecommunications and Energy to issue up $110 million in debt, solely for the purpose of financing the buyout and termination of above-market power contracts. As of January 2000, after termination of the Pilgrim contracts, MMWEC had approximately $36 million in commercial paper notes outstanding.

• The Federal Energy Regulatory Commission (FERC) orders Northeast Utilities (NU) to refund $20,786 to municipals as a result of MMWEC's challenge to a component of NU's transmission rates. This is in addition to a $6 million refund municipals received in 1998 in the same case.

MARCH

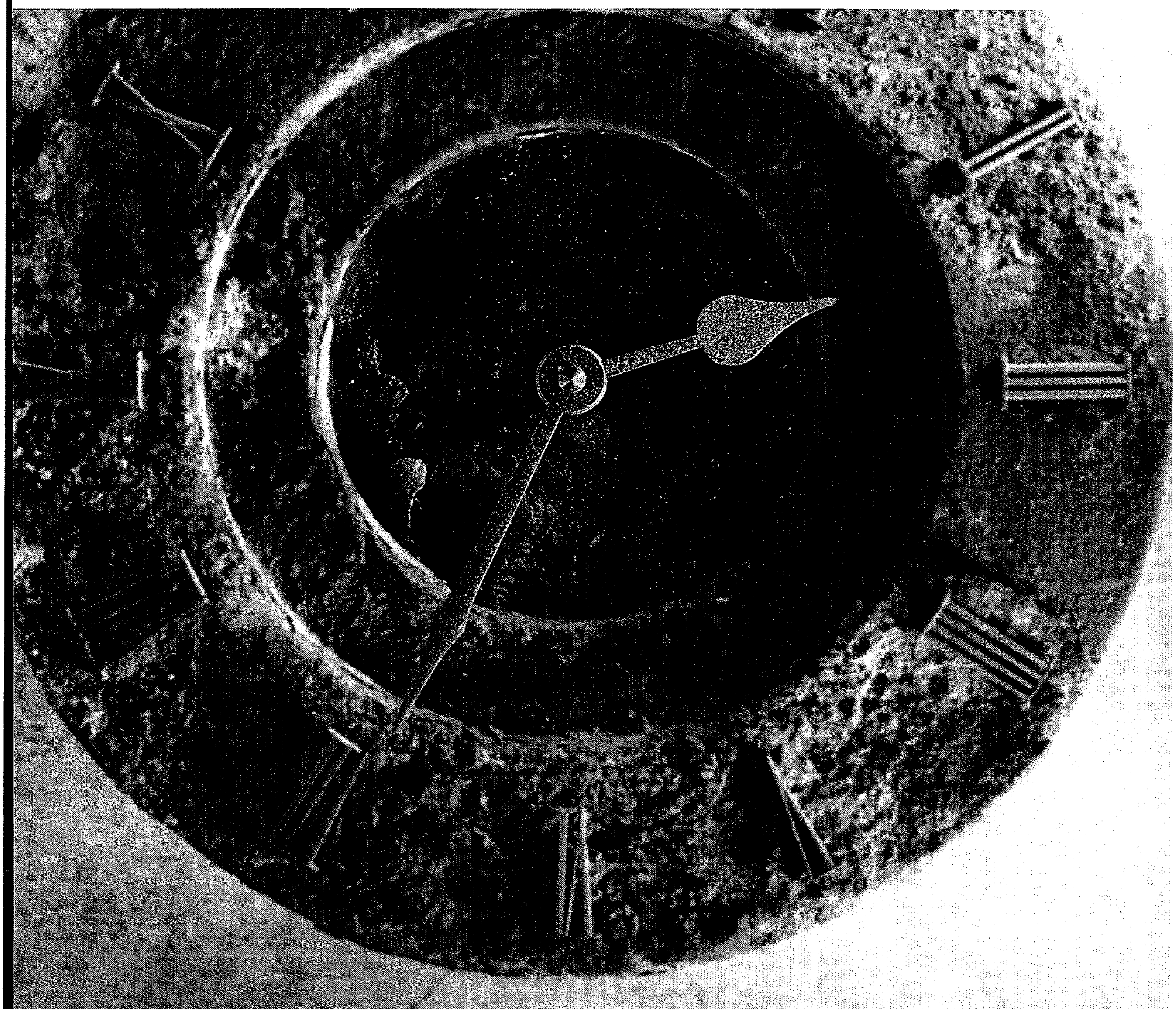
• MMWEC files supplementary draft environmental impact report on its Stony Brook natural gas pipeline project.

• MMWEC staff participates in training and continues upgrading computer systems in preparation for launch of competitive wholesale power markets.

• Board approves annual budgets for MMWEC's power supply projects, which reflect a 13.9 percent decrease in power costs for the contract year beginning July 1, 1999.

MMWEC Jointly-Owned Units

	Stony Brook Intermediate Unit	Stony Brook Peaking Unit	Seabrook Station	Millstone No. 3	W.F. Wyman No. 4
Location	Ludlow, MA	Ludlow, MA	Seabrook, NH	Waterford, CT	Yarmouth, ME
Operator	MMWEC	MMWEC	Northeast Utilities	Northeast Utilities	FPL Energy
Total Capacity	350 MW	170 MW	1,150 MW	1,150 MW	619 MW
MMWEC Ownership	311.3 MW	170 M W	133.3 MW	55.2 MW	22.7 MW



APRIL

• Hydro-Quebec refunds $1.2 million to MMWEC and 23 municipal utilities after settlement of a dispute involving the Hydro-Quebec/New England energy contract.

• Massachusetts Executive Office of Environmental Affairs approves draft environmental impact report on the Stony Brook natural gas pipeline project.

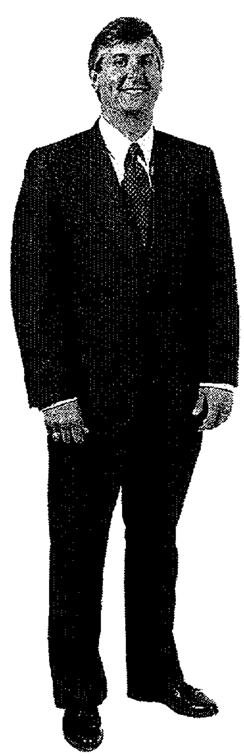
• Stony Brook power plant maintenance outage results in improved heat rate and output for Intermediate Unit.

Although MMWEC's Stony Brook power plant has been operating for nearly 20 years, it could be mistaken for a much newer plant due to the constant upgrading of its mechanical parts and operating systems.

After installing new technology and parts during an April 1999 outage on one of the plant's five gas turbines, Stony Brook returned to service with an improved heat rate and increased electric output. Early in 2000, MMWEC was planning a series of upgrades to the Stony Brook Intermediate Unit that are expected to increase the unit's summer output by up to 27 megawatts. The increased output could yield up to $472,000 in annual savings for Stony Brook's municipal utility participants.

Keeping abreast of combined-cycle and gas turbine technology enables MMWEC to analyze and implement the cost-effective upgrades that keep Stony Brook operating as efficiently as possible.

Gerald P. Skelton
MMWEC Director and Manager of the Templeton Municipal Lighting Plant



Robert V. Jolly, Jr.,
MMWEC Director and Manager of the Marblehead Municipal Light Department

MAY

• NEPOOL files new governance structure with FERC, includes Public Power Sector.

• MMWEC annual meeting. Change in election of MMWEC directors implemented.

MMWEC directors will be elected to three-year, rotating terms under new election rules exercised for the first time at MMWEC's 1999 Annual Meeting.

Previously, MMWEC's seven elected directors were elected to one-year terms, with every director up for re-election at each year's Annual Meeting. The new election rules, which required membership and legislative approval, will help to ensure continuity in board policy. They also eliminate the possibility of a complete turnover of elected directors in any given year.

• MMWEC completes L'Energia contract buyout.

• MMWEC announces ongoing investigation of General Bond Resolution restructuring.

In May 1999, MMWEC announced that it is considering restructuring its General Bond Resolution (GBR) and refunding its outstanding long-term debt to achieve greater financial flexibility.

During the next several months, MMWEC continued its analysis of this debt restructuring plan, which could involve the refunding of all $1.17 billion in MMWEC debt currently outstanding under the GBR. Refunding all the debt would enable MMWEC to amend and restate the GBR to include less restrictive bond covenants, which would give MMWEC more flexibility in managing its assets. Among other things, the restated GBR would ease the existing restrictions on the sale of MMWEC's project assets, including MMWEC's joint ownership interests in several power plants.

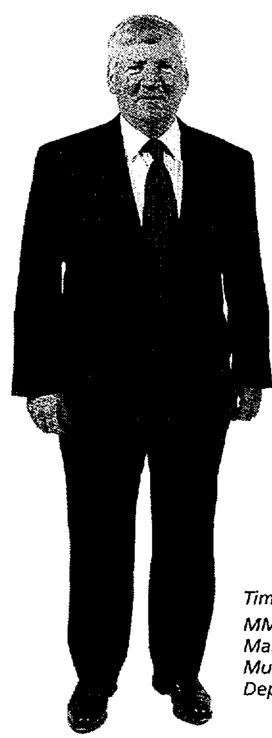
At the same time, MMWEC is considering a more modest financing plan that involves refunding MMWEC's high-interest bonds with lower-interest debt. This alternate plan would achieve a significant level of power cost savings for MMWEC's project participant utilities.

In November, MMWEC filed a petition with the state Department of Telecommunications and Energy (DTE) seeking the debt refunding authority required to implement its GBR restructuring and full debt refunding proposal. Because the DTE must approve MMWEC's long-term bond issues, including refunding bond issues, obtaining DTE approval is a fundamental requirement for implementing the proposal.

Early in April 2000, the DTE approved MMWEC's petition to issue approximately $1.6 billion in bonds or other forms of indebtedness to accomplish its full debt refunding and GBR restructuring plan. MMWEC also has the regulatory authority required to implement its more modest refunding plan, which leaves the company in excellent position to carry out either alternative, depending on participants' preference, interest rates, bond market conditions and other factors.

• ISO New England launches competitive wholesale power markets for NEPOOL. MMWEC staff and computer systems perform well in new electronic marketplace.

Mark T. Kelly
MMWEC Director and Manager of the Middleton Municipal Light Department



Timothy L. McCarthy
MMWEC Director and Manager of the Belmont Municipal Light Department

• MMWEC's Chief Financial Officer is a featured speaker at First Albany Municipal Utilities Conference.

JUNE

• MMWEC meets electric industry's Y2K compliance deadline.

MMWEC met the June 30 deadline of the North American Electric Reliability Council to have mission-critical systems ready to deal with the rollover to the Year 2000 and the infamous Y2K computer bug. After more than a year of work and preparation, MMWEC and most other electric utilities made the transition to the new year without any Y2K-related difficulties.

• MMWEC signs contract with Bay State Gas related to Stony Brook pipeline project.

MMWEC's efforts to increase the supply of natural gas to its Stony Brook power plant moved forward on several fronts in the past year, with one of the key developments being the execution of a natural gas transportation agreement between MMWEC and Bay State Gas Company late in June. Having more natural gas available at Stony Brook will improve the competitive value of the plant, reduce costs for Stony Brook's municipal utility participants by at least $12 million, and reduce the plant's emissions rates.

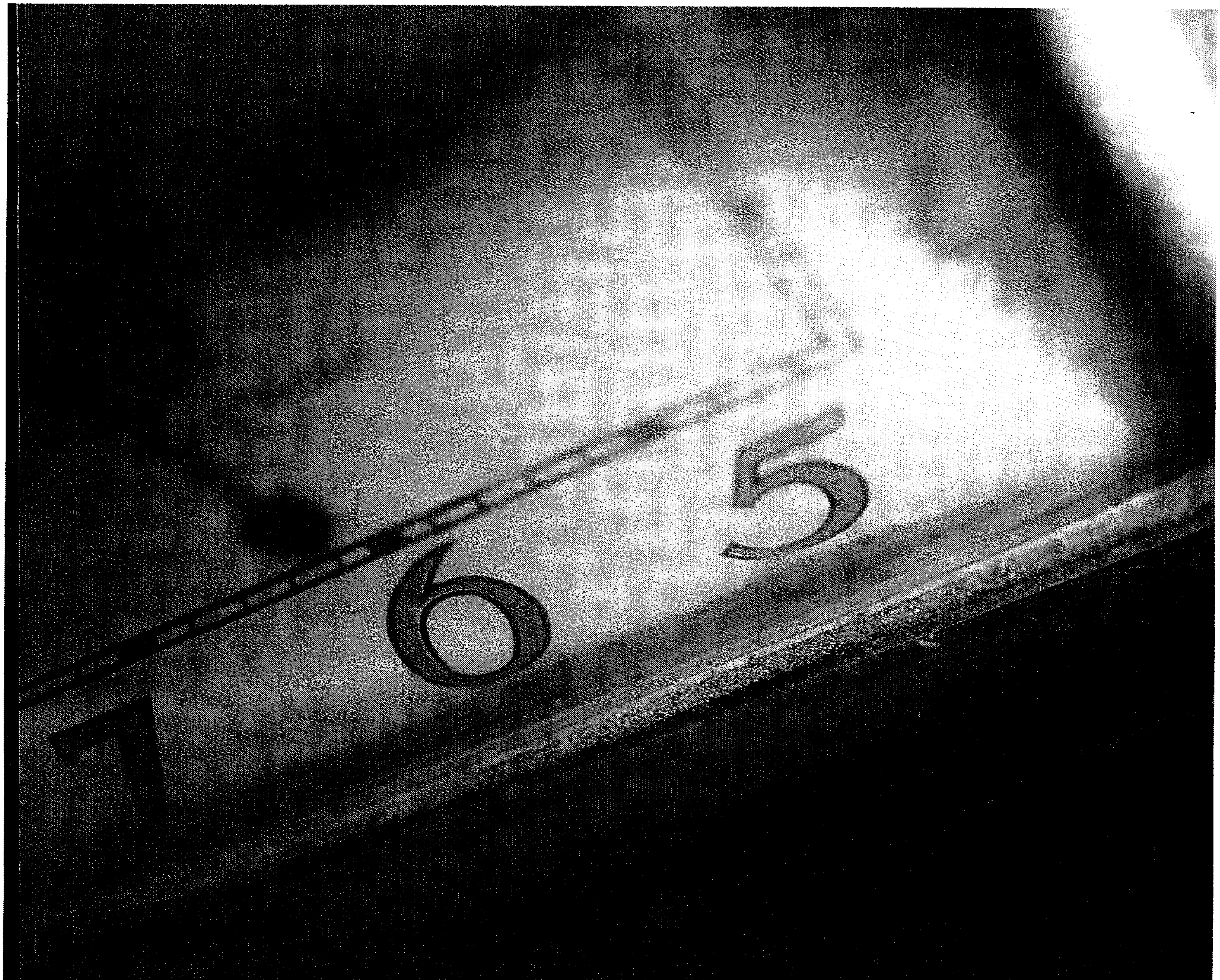
MMWEC has petitioned the state Energy Facilities Siting Board (EFSB) for authority to build a 14.7-mile natural gas pipeline connecting Stony Brook to the interstate pipeline system. Execution of the agreement with Bay State Gas solidifies an MMWEC proposal involving the phased construction of the pipeline, with the first phase being a 5.6-mile pipeline connecting Stony Brook to an existing Bay State Gas pipeline. The agreement provides for the transportation of natural gas over the Bay State Gas system to the 5.6-mile, MMWEC-owned pipeline. The approximate 9-mile second phase of the project, which would extend the pipeline to connect with the interstate pipeline system, would be built only if the agreement with Bay State Gas proved to be inadequate.

Another important milestone for the project was achieved in April 1999, when the state Executive Office of Environmental Affairs approved the Draft Environmental Impact Report for the project. In addition, early in 2000, the EFSB denied a motion by the Town of Wilbraham to dismiss MMWEC's pipeline petition and issued a draft procedural schedule that calls for hearings on the petition to begin this summer. Efforts to obtain the approvals required for construction of the pipeline will continue throughout the year.

• DTE authorizes MMWEC to issue up to $110 million in debt to finance above-market contract buyouts.

JULY

• Suffolk (Mass.) Superior Court rules that NU can be held directly liable for damages stemming from the 27-month shutdown of Millstone Unit 3. MMWEC, which owns 4.8 percent of the unit, is seeking damages from NU stemming from the shutdown.



• FERC approves NEPOOL tariff settlement, which results in more than $6 million in refunds to municipal utilities for "double charges" and reduces future transmission rates.

Massachusetts municipal utilities are receiving more than $6 million in refunds under a settlement of NEPOOL transmission tariff issues approved by the FERC in July.

The NEPOOL transmission tariff, which establishes standard rates for transmission service throughout New England, went into effect, subject to refund, on March 1, 1997. The tariff includes new charges for regional transmission service, as well as other services, and contains numerous provisions describing how new charges are being phased in, old charges are being phased out, and how specific units and contracts are being treated during the transition.

MMWEC argued successfully before the FERC that the tariff resulted in municipal utilities paying twice for certain transmission services - once under the NEPOOL tariff and again under their continuing agreements with transmission service providers. In approving the tariff settlement, the FERC ordered a refund of the double charges covering the period between March 1, 1997 and March 1, 1999. The settlement also either eliminates or mitigates the impact of double charges going forward from March 1999 through March 2003, with savings for this period estimated to be in the $6 million range.

• FERC approves NEPOOL governance restructuring.

Public power's share of voting rights in NEPOOL increased from approximately 7.5 percent to 25 percent when the FERC approved a new NEPOOL governance structure in July.

Under the new structure, the balance of power within NEPOOL shifts dramatically from the region's traditional, investor-owned utilities to public power and the increasing number of non-utilities that are members of NEPOOL. While the added strength for non-utilities is a reflection of the changed composition of NEPOOL, the new rights for public power constitute an unprecedented recognition of the vital role of public power in a restructured electric industry. In fact, the change gives New England's publicly-owned utilities more voting strength than public power has under any other pool governance structure in the country.

The new governance structure initially allocated voting shares equally to four sectors representing the interests of generators, transmission owners, suppliers and public power. The creation of a fifth sector for "end use" entities in April 2000 has resulted in each sector having 20 percent of NEPOOL's voting rights.

This sector voting arrangement reflects an effort to accommodate the increasingly diverse interests of NEPOOL participants, which now include many non-utility generators, power marketers, power brokers and other entities.

While ISO New England, the region's independent system operator, has assumed NEPOOL's previous responsibilities for operating New England's bulk power system, the policies and procedures that govern system operations still originate within the NEPOOL committees. NEPOOL also develops the rules for operation of the region's bulk power markets, with FERC approval required to ensure compliance with applicable laws and regulations.

Having greater voting strength within NEPOOL is especially significant in this light. Over the past year, NEPOOL has been developing new rules and procedures that will have huge financial impacts on wholesale power market participants. During this process, MMWEC has been working with other public power representatives to exercise the public power vote in the most effective manner. In addition to resulting in greater influence for public power on important issues, another benefit of the new governance structure has been enhanced cooperation among the region's public power entities.

It took more than two years and the assistance of a settlement judge appointed through the FERC's Dispute Resolution Service to negotiate the new NEPOOL governance structure. It was during this process that MMWEC made its case for a strong public power sector capable of representing the consumer-oriented interests of non-profit utilities.

AUGUST

• MMWEC Board creates special project to facilitate Pilgrim unit contract buyout and financing.

Edward C. Koeninger
MMWEC Director, representing the Town of Ludlow, Massachusetts

John M. Wesolowski
Treasurer and Chief Financial Officer

• Stony Brook power plant generation increases 25 percent in first three months of new wholesale power markets operation.

Stony Brook's increased operation during the initial months of competitive power markets reflects both the value of the plant in today's changing marketplace and the success of MMWEC's preparations to ensure effective participation in the new markets.

The flexible, quick-start generating capability of Stony Brook and the plant's ability to burn both oil and natural gas make Stony Brook an extremely valuable asset in today's marketplace. In these early months, Stony Brook participants benefited from the plant's higher operating levels and the higher energy clearing prices produced by market forces.

Since the launch of the new marketplace, MMWEC's Internet-based interaction with power system operator ISO New England also has been very successful. This has required the creation and management of new databases, the upgrading of computer equipment and software, and the education and training of employees.

SEPTEMBER

- Belmont Municipal Light Department Manager Timothy L. McCarthy is elected to MMWEC Board of Directors.

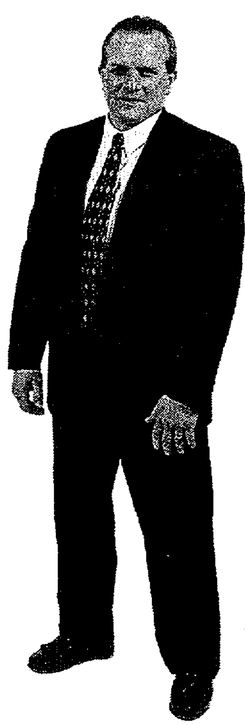
- Massachusetts Division of Energy Resources issues Market Monitor Report showing municipal utility residential rates 12 percent lower than investor-owned utility rates in 1998, the first year of restructured electricity markets in Massachusetts.

Massachusetts Electricity Prices - 1998*	Municipal Utilities	Investor-Owned Distribution Companies
Average Residential Price (cents/kWh)	9.5	10.8
Average Overall Price (cents/kWh)	9.3	9.6

* Source: Market Monitor Report, Massachusetts Division of Energy Resources, September 1999

- Hingham Municipal Lighting Plant becomes eighteenth participant in MMWEC's Home Energy Loss Prevention Service (HELPS) Program.

Through the MMWEC HELPS Program, Massachusetts municipal utilities provide the energy audits and other services required of all utilities under the state Energy Conservation Service Program. Currently, 19 municipal utilities are HELPS Program participants, with Hingham joining the program in September, and the Groton Electric Light Department joining in December.



Ronald C. DeCurzio
Assistant Treasurer and Treasury Department Manager

With a number of revisions to the state program being proposed, MMWEC is exploring the requirements for expanding the HELPS Program to accommodate any changes made at the state level.

OCTOBER

- Open house at Stony Brook site draws about 600 local residents.

An open house celebrating MMWEC's 30th anniversary drew about 600 Ludlow-area residents for tours of the Stony Brook power plant and a variety of other activities. Ludlow Selectmen joined in an anniversary cake-cutting, and two Ludlow Fire Department trucks were on display, with department representatives accepting a $1,000 donation from MMWEC toward the purchase of a thermal imaging device that helps firefighters locate victims in burning buildings.

The open house activities are among MMWEC's many community-oriented projects and programs, which benefit local schools, the business community and other local organizations.

• MMWEC's General Manager and Chief Financial Officer are program speakers at *The Bond Buyer* Conference for municipal bond issuers.

• Representatives of MMWEC visit elected officials and their staffs in Washington, D.C.

• MMWEC installs software and begins implementing new accounting system.

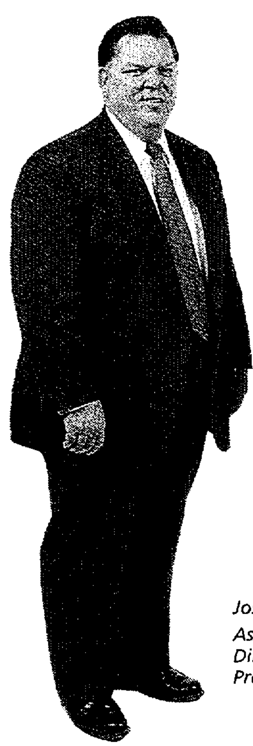
New accounting software installed in October will bring greater efficiency and economy to MMWEC's accounting systems.

The software, which is state-of-the-art and designed to accommodate newer technology, brings online efficiency to MMWEC's general ledger and accounts payable systems, eliminating many manual tasks. It also includes electronic systems for purchasing, receiving and inventory management, streamlining these functions with automatic production of requisitions, purchase orders and other forms.

In addition to processing accounting data electronically, the new software also produces a variety of reports to enhance accounting controls. MMWEC staff is working to have the software package fully functional by mid-2000.

• ISO New England proposes 2000 budget of $71.5 million, a 30 percent increase.

The escalating costs of restructuring New England's wholesale power market were evident in ISO-New England's 2000 budget proposal, which reflected an increase of about 30 percent from 1999. Among other things, the budget proposed hiring more ISO staff and funding capital additions needed to implement new market systems.



Joseph O. Roy
Assistant Secretary and Director of Operating Projects

The proposed budget ran into difficulty at the NEPOOL Budget and Finance Committee, which was chaired by Roger W. Bacon, MMWEC's Power Supply Director. Bacon's committee, and ultimately the NEPOOL Participants' Committee, ended up approving a plan to amortize certain capital and market restructuring expenses over five-year periods, spreading the costs to include future NEPOOL participants that benefit from these initiatives.

This and other elements of the plan minimized the amount of ISO restructuring expenses to be paid by municipal utilities in 2000, demonstrating the value of MMWEC's work in the NEPOOL arena on behalf of its members.

NOVEMBER

• MMWEC files petition with DTE seeking authority to refund all of its outstanding long-term debt.

• Moody's issues MMWEC credit analysis that maintains Baa2 rating and notes increasing stability.

In a November 1999 credit analysis, Moody's Investors Service states that its credit outlook on MMWEC "has become more stable ... because of an improving consensus on the direction of its strategic plans and their implementation." The analysis cites the positive influence of MMWEC's General Manager in building consensus among members and participants.

Moody's also states that MMWEC's project participants "are making continued progress in building reserves in order to lower power rates when the marketplace may require it" to mitigate the impact of stranded costs. While it cites stranded costs as a continuing risk, Moody's also states that MMWEC's credit quality "is buoyed by the solid operating performance of its power plants, the diversity of its power resources, and the match between its load requirements and capacity."

In addition, Moody's cites as a positive development MMWEC's plans that could lead to refunding of the company's long-term debt and restructuring of its General Bond Resolution to provide more flexibility in managing MMWEC assets.

DECEMBER

- MMWEC completes Pilgrim contract buyout.

- MMWEC makes a successful and uneventful transition to Year 2000.

- NEPOOL files information on congestion management and multi-settlement market systems with FERC.

- Board approves 2000 A&G budget, which includes new staff positions for marketing, public relations and auditing.

- The FERC rules in favor of MMWEC's challenge to a change in NU's open access transmission tariff rates, resulting in a refund of more than $600,000 to municipal utilities receiving transmission service from NU.

In this filing, NEPOOL provides the FERC with information on a compromise proposal for congestion management (CMS) and multi-settlement (MSS) market systems. The FERC earlier ordered NEPOOL to develop and implement these systems, which have been the subjects of lengthy and controversial negotiations.

The CMS is intended to fairly allocate transmission capacity and increased energy costs when portions of the region's transmission system become congested or overburdened. Under the proposed CMS, costs would be higher for customers in congested areas.

The proposed MSS represents a change from the current real-time settlement system to one where markets would settle once in a financially binding, day-ahead forward market and again in a real-time market. Among other things, the MSS is intended to limit opportunities for market power abuse.

Implementation of the CMS/MSS will have significant financial impacts on many NEPOOL participants, including many municipal utilities. However, as of March 2000, NEPOOL had been unable to agree on a formal CMS/MSS proposal for the FERC and controversy over the new systems remained high.

The most recent and widely accepted versions of the CMS include provisions for long-term transmission planning and expansion that were incorporated at the insistence of MMWEC and other public power entities. These include requirements to identify and then alleviate the transmission constraints that cause the imposition of congestion charges.

The procedural and technical complexity of developing these new market systems has required an ongoing commitment of MMWEC resources to shape, track, analyze and explain new developments, which occur almost daily. This especially is an area where MMWEC is building on each day's accomplishments to protect the future interests of municipal utilities and consumers.

- Groton Electric Light Department joins HELPS program.

- FERC order on ISO New England's 2000 tariff structure reflects MMWEC's arguments, saving municipal utilities $1.5 million.

Nicholas J. Scobbo, Jr.
General Counsel

JANUARY 2000

• DTE holds public hearing on MMWEC's debt refunding petition.

• Representatives of MMWEC attend APPA legislative rally in Washington, D.C. and visit with elected officials.

• Westfield Gas & Electric Light Department Manager Daniel Golubek is elected to MMWEC Board of Directors.

• MMWEC outlines new strategic plan at Membership Meeting.

At this meeting, MMWEC explained its year-long strategic planning initiative, which focuses on strengthening the financial viability and increasing the competitiveness of member utilities. The plan details numerous strategies that will enable MMWEC and its members to capture the benefits and opportunities presented by restructuring of the electric industry.

In addition to expanding the range of service choices for member and non-member municipal utilities, the strategic plan proposes the establishment of new business initiatives to serve non-member utilities and other potential customers, such as municipal power aggregators and non-profit entities. While these new initiatives would emanate primarily from MMWEC's traditional power supply and financial capabilities, they also could include a broader array of energy and other services. Distributed generation, the Internet and other telecommunications services are among the areas holding potential for increased MMWEC involvement.

Significantly, the strategic plan assumes no change in MMWEC's enabling legislation, Chapter 775 of the Acts of 1975, relying instead on existing law and authority to accomplish its objectives.

As these initiatives are developed over the next several years, and as the structure and economics of New England's energy marketplace continue to change, MMWEC will keep its strategic planning process in motion, searching for opportunities that benefit municipal utilities and the consumers they serve. This process, combined with MMWEC's focus on seizing the opportunities of each new day, has positioned MMWEC for success in a changing environment, as evidenced by its accomplishments over the past year.

MMWEC's president and two directors are not pictured in this year's annual report. They are: **John W. Kilgo, Jr.**, MMWEC President and Manager of the Sterling Municipal Light Department; **John M. Flynn**, MMWEC Director, representing the Town of Hampden, Massachusetts; and **Michael J. Flynn**, MMWEC Director, representing the Town of Wilbraham, Massachusetts.

Edla A. Bloom, former Director of the Holden Municipal Light Department, and **Joseph R. Spadea, Jr.**, former Manager of the Hingham Municipal Lighting Plant, served partial terms as MMWEC Directors during the past year.

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

FINANCIAL STATEMENTS

With Supplementary Information
December 31, 1999, 1998 and 1997
With Independent Auditors' Report Thereon

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Independent Auditors' Report

The Board of Directors

Massachusetts Municipal Wholesale Electric Company

We have audited the accompanying statements of financial position of Massachusetts Municipal Wholesale Electric Company (a Massachusetts public corporation) as of December 31, 1999, 1998 and 1997 and the related statements of operations and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Massachusetts Municipal Wholesale Electric Company as of December 31, 1999, 1998 and 1997, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

KPMG LLP

March 10, 2000

Statements of Financial Position

December 31, 1999, 1998 and 1997

(In Thousands)	1999	1998	1997
ASSETS			
Electric Plant			
In Service (Note 4)	$1,240,200	$1,238,454	$1,237,341
Accumulated Depreciation	(500,389)	(456,650)	(414,028)
	739,811	781,804	823,313
Nuclear Fuel - Net of Amortization	9,736	12,164	11,452
Total Electric Plant	749,547	793,968	834,765
Special Funds (Notes 2, 3 and 5)	241,042	239,547	226,141
Current Assets			
Cash and Temporary Investments (Note 5)	1,081	1,718	1,307
Accounts Receivable	6,580	6,678	9,234
Unbilled Revenues (Note 2)	3,300	3,776	5,593
Inventories (Note 2)	18,505	13,747	14,463
Prepaid Expenses	6,470	8,488	7,023
Total Current Assets	35,936	34,407	37,620
Total Special Funds and Current Assets	276,978	273,954	263,761
Deferred Charges			
Amounts Recoverable Under Terms of the Power Sales Agreements (Note 2)	238,565	223,670	208,314
Unamortized Debt Discount and Expenses	22,448	24,815	27,147
Nuclear Decommissioning Trusts	18,142	14,713	12,072
Other	6,308	6,024	5,160
	285,463	269,222	252,693
	$1,311,988	$1,337,144	$1,351,219
LIABILITIES			
Long-Term Debt			
Bonds Payable (Note 3)	$1,130,215	$1,178,085	$1,222,735
Current Liabilities			
Current Maturities of Long-Term Debt (Note 3)	47,870	44,650	41,315
Commercial Paper (Note 3)	36,765	21,205	—
Notes Payable (Note 3)	82	—	—
Accounts Payable	9,860	7,514	12,241
Accrued Expenses	21,501	17,696	14,712
Member and Participant Advances and Reserves	46,915	52,538	47,302
	162,993	143,603	115,570
Deferred Credits	18,780	15,456	12,914
Commitments and Contingencies (Note 9)			
	$1,311,988	$1,337,144	$1,351,219

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

Statements of Operations

Years Ended December 31, 1999, 1998 and 1997

(In Thousands)	1999	1998	1997
Revenues (Note 2)	$232,094	$227,949	$242,502
Interest Income	15,409	15,286	14,553
Total Revenues and Interest Income	$247,503	$243,235	$ 257,055
Operating and Service Expenses:			
Fuel Used in Electric Generation	$ 28,290	$ 27,530	$ 27,824
Purchased Power	37,420	41,754	45,421
Other Operating	39,367	35,028	36,796
Maintenance	15,207	12,108	19,206
Depreciation	45,032	44,837	44,699
Taxes Other Than Income	5,645	5,652	6,298
	170,961	166,909	180,244
Interest Expense:			
Interest Charges	68,796	70,711	72,854
Interest Charged to Projects During Construction (Note 2)	(19)	(95)	(45)
	68,777	70,616	72,809
Total Operating Costs and Interest Expense	239,738	237,525	253,053
Other (Note 7)	18,874	22,000	—
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements (Note 2)	(11,109)	(16,290)	4,002
	$247,503	$243,235	$ 257,055

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

Statements of Cash Flows

Years Ended December 31, 1999, 1998 and 1997

(In Thousands)	1999	1998	1997
Cash flows from operating activities:			
Total Revenues and Interest Income	$ 247,503	$ 243,235	$ 257,055
Total Costs and Expenses, net	(258,612)	(259,525)	(253,053)
Adjustments to arrive at net cash provided by operating activities:			
Depreciation and Decommissioning	47,502	46,609	46,405
Amortization	7,829	6,635	6,693
Change in current assets and liabilities:			
Accounts Receivable	98	2,556	(3,021)
Unbilled Revenues	476	1,817	1,027
Inventories	(4,758)	716	(590)
Prepaid Expenses	2,018	(1,465)	5,370
Accounts Payable	2,346	(4,727)	(3,827)
Accrued Expenses and Other	3,413	2,027	(563)
Member and Participant Advances and Reserves	(5,623)	5,236	(8,036)
Net cash provided by operating activities	42,192	43,114	47,460
Cash flows from investing activities:			
Construction Expenditures and Purchases of Nuclear Fuel	(6,037)	(8,171)	(5,113)
Interest Charged to Projects During Construction	(19)	(95)	(45)
Net Increase in Special Funds	(1,495)	(13,406)	(2,439)
Change in net Unrealized Gain (Loss) on Special Funds	(3,785)	934	537
Decommissioning Trust Payments, net	(3,429)	(2,641)	(2,396)
Other	1,087	1,062	1,328
Net cash used for investing activities	(13,678)	(22,317)	(8,128)
Cash flows from financing activities:			
Payments for Principal of Long-Term Debt and Commercial Paper	(48,230)	(42,610)	(39,415)
Proceeds from Commercial Paper	19,140	22,500	—
Payments for Commercial Paper Issue Costs	(143)	(276)	—
Change in Notes Payable	82	—	—
Net cash used for financing activities	(29,151)	(20,386)	(39,415)
Net increase (decrease) in cash and temporary investments	(637)	411	(83)
Cash and Temporary Investments at Beginning of Year	1,718	1,307	1,390
Cash and Temporary Investments at End of Year	$ 1,081	$ 1,718	$ 1,307
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 65,885	$ 67,714	$ 69,854

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

Notes to Financial Statements

December 31, 1999, 1998 and 1997

(1) Nature of Operations

The Massachusetts Municipal Wholesale Electric Company (MMWEC) is a public corporation and a political subdivision of the Commonwealth of Massachusetts formed to be a joint action agency and to develop a bulk power supply for its member Massachusetts municipal electric systems and other utilities. MMWEC is authorized to construct, own, or purchase ownership interests in, and to issue revenue bonds to finance, electric facilities (Projects) secured by MMWEC's revenues derived from Power Sales Agreements (PSAs) with its members and other utilities. The power supply program consists of power purchase arrangements, power supply planning and brokering services, financial services, and the Projects, which consist of ownership interests in generating facilities built and operated by MMWEC and other utilities.

A Massachusetts city or town having a municipal electric system, authorized by majority vote of the city or town, may become a member of MMWEC by applying for admission and agreeing to comply with the terms and conditions of membership as the MMWEC By-Laws may require. As of December 31, 1999, twenty-two Massachusetts municipal electric systems were members. Termination of membership does not relieve a system of its PSA obligations.

(2) Significant Accounting Policies

MMWEC presents its financial statements in accordance with generally accepted accounting principles as promulgated by the Financial Accounting Standards Board which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Interest Charged to Projects During Construction

MMWEC capitalizes interest as an element of the cost of electric plant and nuclear fuel in process. A corresponding amount is reflected as a reduction of interest expense. The amount of interest capitalized is based on the cost of debt, including amortization of debt discount and expenses, related to each Project, net of investment gains and losses and interest income derived from unexpended Project funds.

Nuclear Fuel

Nuclear fuel, net of amortization, includes MMWEC's ownership interest of fuel in use, in stock and in process for Millstone Unit 3 and Seabrook Station. The cost of nuclear fuel is amortized to Fuel Used in Electric Generation based on the relationship of energy produced in the current period to total expected energy production for fuel in the reactor. A provision for fuel disposal costs is included in Fuel Used in Electric Generation based upon disposal contracts with the Department of Energy (DOE). In addition, Fuel Used in Electric Generation includes the annual assessment, under the Energy Policy Act of 1992, for the cost of decontamination and decommissioning of uranium enrichment plants operated by the DOE. Billings from the DOE will occur over the next eight years. At December 31, 1999, MMWEC's share of Millstone Unit 3 and Seabrook Station unbilled assessments was $323,000 and $490,000, respectively. The amounts are included in Other Deferred Charges and Deferred Credits on the Statements of Financial Position.

Special Funds

The Special Funds, other than certain Working Capital Funds, are invested in accordance with the General Bond Resolution (GBR). The composition of Special Funds is as follows:

(In Thousands)	1999	1998	1997
Fund			
Bond Fund Interest, Principal and Retirement Account to pay principal and interest on bonds	$ 45,427	$ 43,742	$ 37,507
Bond Fund Reserve Account set at the maximum annual interest obligation to make up any deficiencies in the Bond Fund Interest, Principal and Retirement Account	77,904	80,216	79,942
Reserve and Contingency Fund to make up deficiencies in the Bond Fund and pay for renewals and extraordinary costs	24,113	22,840	21,559
Revenue Fund to receive revenues and disburse them to other funds	73,625	66,842	67,669
Working Capital Funds to maintain funds to cover operating expenses	19,973	25,907	19,464
Total Special Funds	$241,042	$239,547	$226,141

Cash and Temporary Investments

Certain cash and temporary investment amounts used for power purchases and working capital requirements of MMWEC are not subject to the provisions of the GBR. In addition to the investment securities delineated in the GBR, MMWEC invests in repurchase agreements with banks where MMWEC has established accounts.

Revenues and Unbilled Revenues

Revenues include electric sales for resale provided under MMWEC's power supply program which consists of billings under the PSAs, Power Purchase Agreements and related power brokering arrangements. MMWEC provides its members with power supply planning and related services which are billed as Service Revenues. Amounts which are not yet billed are included in Unbilled Revenues on the Statements of Financial Position. Revenues are comprised of the following:

(In Thousands)	1999	1998	1997
Revenues			
Electric sales for resale	$230,570	$225,690	$237,795
Service	1,524	1,426	1,653
PSNH Settlement	—	833	2,000
Gain on land taken by eminent domain	—	—	1,054
Total Revenues	$232,094	$227,949	$242,502

Inventories

Fuel oil and spare parts inventory are recorded and accounted for by the average cost method. At December 31, 1999, 1998 and 1997, fuel oil inventory was valued at $5.7, $4.9 and $4.7 million, and spare parts inventory amounted to $12.8, $8.8 and $9.8 million, respectively.

Amounts Recoverable Under Terms of the Power Sales Agreements

Billings to Project Participants are designed to recover costs pursuant to the terms of the PSAs to provide for debt service, operating funds and reserve requirements. Expenses are reflected in the Statements of Operations in accordance with generally accepted accounting principles. The timing difference between amounts billed and expensed is charged or credited to Amounts Recoverable Under Terms of the PSAs. Amounts will be recovered through future billings or an expense will be recognized to offset credit balances. The principal differences include depreciation, fuel amortization, costs associated with canceled Projects, cost of refunding, billing for certain interest, reserves, net unrealized gain or loss on securities available for sale and other costs. Individual Projects have a cumulative deferral of costs which total $245.1, $228.8 and $212.9 million and have cumulative billings in excess of costs which total $6.5, $5.1 and $4.6 million at December 31, 1999, 1998 and 1997, respectively. These amounts have been netted in the Statements of Financial Position.

The December 31, 1999, 1998 and 1997 balances of $238.6, $223.7 and $208.3 million, respectively, reflects the Statements of Operations net decrease (increase) of ($11.1), ($16.3) and $4.0 million for the years then ended and the change in net unrealized gain (loss) on securities available for sale of ($3.8), $.9 and $.6 million for 1999, 1998 and 1997, respectively.

Nuclear Decommissioning Trusts

MMWEC maintains external trust funds, as promulgated by Nuclear Regulatory Commission and state regulations, to provide for the decommissioning activities of Millstone Unit 3 and Seabrook Station. The December 31, 1999 Millstone Unit 3 and Seabrook Station balances of $8,012 and $10,130 million, respectively, are stated at cost and are included as part of the Deferred Charges and Deferred Credits on the Statements of Financial Position. MMWEC's share of the estimated reserve requirement for the prompt dismantling and removal of the Millstone Unit 3 and Seabrook Station, at the expiration of their original operating licenses in 2025 and 2026, is $30 and $66 million, respectively.

Depreciation

Electric plant in service is depreciated using the straight-line method. The aggregate annual provisions for depreciation for 1999, 1998 and 1997 averaged 4% of the original cost of depreciable property.

Interest Rate Protection Agreement

Premiums paid for the purchase of an Interest Rate Protection Agreement are amortized to interest expense over the term of the agreement. Unamortized premiums are included in Other Deferred Charges in the Statements of Financial Position.

Reclassifications

Certain reclassifications have been made to the Financial Statements for prior years to conform to the 1999 presentation.

(3) Debt

Power Supply System Revenue Bonds

MMWEC financings, other than obligations maturing within one year, require Massachusetts Department of Telecommunications and Energy authorization. To finance the ownership interests in electric generating facilities under its GBR, MMWEC issued Power Supply System Revenue Bonds (Bonds). The Bonds are secured under the GBR by a pledge of the revenues derived by MMWEC under the terms of the PSAs and from the ownership and operation of the Projects in its power supply system. Pursuant to the PSAs, each Project Participant is obligated to pay its share of the actual costs relating to the generating units planned, under construction or in operation. The Project Participants' obligations are not contingent upon the completion or operational status of the units.

Bonds Payable consists of serial, term and variable-rate bonds and are comprised of the following issues:

(In Thousands)	Issue	Net Interest Cost	December 31, 1999	1998	1997
	1987 Series A	8.9%	$ 7,110	$ 7,850	$ 8,525
	1992 Series A	7.0%	89,805	92,285	94,625
	1992 Series B	7.0%	174,470	180,495	186,170
	1992 Series C	6.9%	54,295	55,740	57,095
	1992 Series D	6.3%	75,395	77,990	80,460
	1992 Series E	6.0%	75,735	84,615	92,865
	1993 Series A	5.3%	329,100	343,390	356,030
	1994 Series A	5.3%	113,130	113,670	114,195
	1994 Series B	5.1%	161,445	169,100	176,485
	1994 Series C	Variable	97,600	97,600	97,600
Bonds Payable			1,178,085	1,222,735	1,264,050
Less: Current Maturities			(47,870)	(44,650)	(41,315)
Total Long-Term Debt			$1,130,215	$1,178,085	$1,222,735

The serial and term bonds are generally subject to optional redemption approximately ten years after the issue date, at 103% of the principal amount, descending periodically thereafter to 100%. The aggregate annual principal payments due on the bonds in the next five years are as follows: 2000 - $47.9 million; 2001 - $50.6 million, 2002 - $53.4 million; 2003 - $56.6 million and 2004 – $60 million.

The interest rates on the 1994 Series C variable-rate bonds are adjusted from time-to-time and bondholders may require repurchase of the 1994 Series C bonds at the time of such interest rate adjustment. The 1994 Series C bonds are backed by a liquidity facility with a bank providing for the purchase, by the bank, of the 1994 Series C bonds if the bonds cannot be remarketed and a credit facility with an insurance company guaranteeing the payment of the principal and interest on the 1994 Series C bonds. The debt service on the 1994 Series C bonds is on a parity with the senior lien fixed-rate bonds to the extent that the debt service on the 1994 Series C bonds is equal to or less than the debt service on the bonds refunded by the 1994 Series C bonds in a given bond year.

Debt Service Forward Delivery Agreement

In conjunction with the issuance of the 1994 Series C bonds, MMWEC entered into a seven year Debt Service Forward Delivery Agreement (Forward Agreement) for purposes other than trading. MMWEC makes monthly deposits to the various accounts within the Bond Fund for the semiannual payment of its debt service on its outstanding bonds. In exchange for the right to direct the investment of such monies, the counterparty pays a fixed amount to MMWEC on a periodic basis, providing MMWEC a fixed yield that could be earned on a security with a five to seven year maturity purchased at the time the contract was executed, while complying with the maturity limitations for investments in the Bond Fund under the terms of the GBR. The counterparty has the right to sell to MMWEC Government Obligations that mature prior to the relevant debt service payment dates during the term of the Forward Agreement.

MMWEC reserves the right to terminate the Forward Agreement in whole or in part in connection with any purchase, redemption or refunding of fixed-rate bonds, counterparty default or counterparty credit rating deterioration to below investment grade. The Forward Agreement provides for the calculation and payment of liquidated damages to the counterparty reflecting market interest rates at the time of the termination compared to the rate levels in the Forward Agreement.

The cash requirement under the Forward Agreement requires MMWEC to make available to the counterparty an average balance of $30.3 million over the seven year term of the agreement in exchange for investments in Government Securities, to be held by MMWEC's trustee, that mature prior to MMWEC's debt payment dates.

The Forward Agreement is not recognized in the Statements of Financial Position to the extent that settlement of cash in exchange for financial instruments has not occurred. To the extent cash has been exchanged for Government Securities, the Government Securities are recorded on the Statements of Financial Position as Special Funds.

Interest Rate Protection Agreement

The 1994 Series C bonds provide a hedge against interest rate risk on the net funding cost of approximately $100 million of short-term floating rate investment assets. MMWEC purchased a $41 million Interest Rate Protection Agreement (Cap Agreement), comprised of an $11 million tranche with a protection rate of 6.85% expiring on June 30, 2000, and a $30 million tranche with a protection rate of 7.25% expiring on June 30, 2002, to limit the interest rate exposure on a portion of the 1994 Series C variable-rate debt to the extent that the variable debt costs exceed the fixed-rate received on the Forward Agreement described above.

MMWEC purchased the right to receive annually an amount by which an index-based interest rate, which approximates the interest rate on the 1994 Series C bonds, exceeds the protection rate in the Cap Agreement. MMWEC has the right to terminate the Cap Agreement if the provider or its guarantor's credit rating falls below a double A and receive payment of liquidation damages designed to enable MMWEC to enter into an equivalent agreement. The cost of the Cap Agreement was paid up front and is included in Other Deferred Charges on the Statements of Financial Position. There are no future MMWEC cash requirements under the terms of the Cap Agreement. The Cap Agreement was purchased for purposes other than trading.

Net Revenue Available for Debt Service

In accordance with the provisions of MMWEC's GBR, MMWEC covenants that it shall fix, revise and collect rates, tolls, rents and other fees and charges, sufficient to produce revenues to pay all operating and maintenance expenses and principal of, premium, if any, and the interest on the Bonds and to pay all other obligations against its revenue. Revenues, which include applicable interest earnings from investments, are required to equal 1.10 times the annual debt service for each contract year ending June 30, after deduction of certain operating and maintenance expenses and exclusive of depreciation. For the contract years ended June 30, 1999, 1998, 1997 and prior years, MMWEC met the GBR debt service coverage requirements for the applicable MMWEC Projects.

	Contract Year Ended June 30,		
(In Thousands)	1999	1998	1997
Debt Service Coverage:			
Revenues	$185,786	$191,245	$171,378
Other Billings	574	576	576
Reserve and Contingency Fund Billings	11,076	11,626	11,159
Total	197,436	203,447	183,113
Less: Operating & Maintenance Expenses	(75,604)	(75,566)	(60,371)
Available Revenues Net of Expenses	$121,832	$127,881	$122,742
Debt Service Requirement	$110,756	$116,255	$111,583
Coverage (110% Required)	110%	110%	110%

Notes Payable

MMWEC maintains a $5 million revolving line of credit to finance temporarily certain power purchases made by MMWEC for resale under power purchase contracts. Borrowings outstanding under the line of credit were $82,000, $0 and $0 at December 31, 1999, 1998 and 1997. During 1999, 1998 and 1997 the maximum outstanding balance under the line of credit was $2,385,000, $90,000 and $167,600, respectively. Interest charged on borrowings under the line of credit is at the bank's prime rate, which was 8.5% at December 31, 1999, minus one percent. In addition, a commitment fee of one quarter of 1% per annum is charged on the unused portion of the line based on the average daily principal amount of the loan outstanding.

Commercial Paper

In 1999, MMWEC issued its Series B Power Purchase commercial paper program notes for $40.3 million. The Series B notes encompassed $19.1 million on new commercial paper notes and refunding of the outstanding $21.2 million of Series A commercial paper notes issued in 1998. The commercial paper notes are not subject to redemption prior to maturity but are subject to acceleration upon the occurrence of an Event of Default under the Resolution. The Series B Notes are a special obligation of MMWEC payable solely from the revenues and other monies specified in the Series B Power Purchase Resolution. A four-year bank letter of credit in the amount of $40 million provides security for the payment of principal and interest on the Series B Notes. The December 31, 1999 commercial paper notes outstanding balance was $36.8 million at an interest rate of 3.2%.

(4) Electric Generation Facilities and Financing

MMWEC's power supply capacity includes ownership interests in the Stony Brook Peaking and Intermediate units which it operates. MMWEC is a nonoperating joint owner in the W.F. Wyman Unit No. 4, Millstone Unit 3 and Seabrook Station units. Electric Plant In Service also includes MMWEC's Service Operations which totalled $2.6, $2.5 and $2.7 million in 1999, 1998 and 1997, respectively. The following is a summary of Projects included in Electric Plant In Service and MMWEC's share of capability.

(In Thousands)	Facility and MMWEC Share of Capability (MW)		Amounts as of December 31, 1999	1998	1997
Peaking Project	Stony Brook	170.0	$ 56,380	$ 56,338	$ 56,310
Intermediate Project	Stony Brook	311.3	151,337	153,968	152,786
Wyman Project	W.F. Wyman No. 4	22.7	7,341	7,365	7,361
Nuclear Project No. 3	Millstone Unit 3	36.8	130,048	129,814	129,595
Nuclear Mix No. 1	Millstone Unit 3	18.4	51,517	51,400	51,290
Nuclear Mix No. 1	Seabrook Station	1.9	8,616	8,599	8,589
Nuclear Project No. 4	Seabrook Station	49.8	259,630	259,204	258,925
Nuclear Project No. 5	Seabrook Station	12.6	71,038	70,930	70,859
Project No. 6	Seabrook Station	69.0	501,688	501,098	500,712
			$1,237,595	$1,238,716	$1,236,427

(5) Investments and Deposits

All bank deposits, which amounted to $208,000 at December 31, 1999, are maintained at one financial institution. The Federal Deposit Insurance Corporation currently insures up to $100,000 per depositor. MMWEC's uninsured deposits ranged from zero to $4.7 million during 1999 due to seasonal cash flows, and the timing of daily cash receipts. At December 31, 1999, 1998 and 1997 investments are classified as available for sale and reported at fair value with unrealized gains of $.7, $2.7, and $1.8 million, respectively, and unrealized losses of $1.8 million, $47,000 and $76,000 excluded from earnings and reported as a component of Amounts Recoverable Under the Terms of the Power Sales Agreement on the Statements of Financial Position. At December 31, 1999, all securities underlying repurchase agreements, and all other investments, were held in MMWEC's name by custodians consisting of the Bond Fund Trustee or MMWEC's depository bank. Investments, representing the Special Funds and Cash and Temporary Investments, as well as certain additional amounts disbursed but available for investment, and accrued interest, are presented below:

	1999		1998		1997	
(In Thousands)	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value
Repurchase Agreements	$ 3,899	$ 3,899	$ —	$ —	$ 1,523	$ 1,573
Other Investments:						
U.S. Treasury bills	22,457	22,985	20,825	21,524	19,215	19,799
U.S. Treasury notes	77,146	75,913	79,077	80,866	83,141	84,049
U.S. Agency bonds	29,142	28,651	—	—	—	—
Municipal bonds	8,199	8,228	7,089	7,276	7,159	7,381
U.S. Agency discount notes	102,519	102,565	133,010	133,000	114,086	114,053
Total Other Investments	239,463	238,342	240,001	242,666	223,601	225,282
Total Investments	$243,362	$242,241	$240,001	$242,666	$225,124	$226,855

During 1999, 1998 and 1997, the proceeds from the sale of available for sale securities were $33.1, $0 and $.5 million resulting in gross realized gains of $70,000, $0 and $0 and gross realized losses of $66,000, $0 and $67, respectively. The basis on which cost was determined in computing realized gain or loss was specific identification. Including repurchase agreements, the average contractual maturity of the investments in debt securities at December 31, 1999, 1998 and 1997 were 530, 347 and 393 days, respectively.

Due to seasonal cash flows during 1999, 1998 and 1997, MMWEC, from time-to-time, invested in repurchase agreements with its depository bank that were collateralized by securities in MMWEC's name held by the depository bank. MMWEC's practice is to monitor the market value of the underlying securities to ensure that the market value equals or exceeds the amount invested. Market values of the securities are based on independent quoted market prices.

(6) Fair Values of Financial Instruments

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

Investments and Decommissioning Trusts - The fair values estimated are based on quoted market prices for those or similar investments.

Long-Term Debt - The fair value is estimated based on quoted market prices for the same or similar issues.

Interest Rate Protection Agreement - The fair value is based on average quoted market prices of agreements with similar duration and strike prices.

Debt Service Forward Delivery Agreement - The fair value generally reflects the estimated amounts that MMWEC would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current unrealized gains or losses of open contracts.

The estimated fair values of MMWEC's financial instruments are as follows:

	1999		1998		1997	
(In Thousands)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Financial Assets:						
Investments	$ 242,241	$ 242,241	$ 242,666	$ 242,666	$ 226,855	$ 226,855
Decommissioning Trusts	18,142	20,925	14,713	17,310	12,072	13,290
Interest Rate Protection Agreement	152	150	263	75	375	178
Financial Liabilities:						
Long-Term Debt	1,130,215	1,135,393	1,178,085	1,229,525	$1,222,735	1,262,465
Unrecognized Financial Instruments:						
Debt Service Forward Delivery Agreement	—	891	—	3,070	—	3,313

The carrying amounts for Cash, Accounts Receivable, Notes Payable, Accounts Payable and Accrued Expenses approximate their fair value due to the short-term nature of these instruments.

(7) Other Charges and Credits to Income

In 1999 and 1998, MMWEC negotiated the payment of $18.9 and $22 million, which was financed through the issuance of $19.1 and $22.5 million in commercial paper notes, respectively, for the buy-out and termination of uneconomical Power Purchase Contracts under which MMWEC had agreed to purchase electric capacity and output for resale to certain cities and towns of the Commonwealth having municipal electric departments.

(8) Benefit Plans

MMWEC has two non-contributory defined benefit pension plans covering substantially all full-time active employees. One plan covers union employees (union plan) and the other plan covers non-union employees (non-union plan). The amount shown below as the Pension Benefit Obligation for MMWEC is a standardized disclosure measure of the present value of pension benefits, adjusted for the effect of projected salary increases, estimated to be payable in the future as a result of employee service to date. The measure is the actuarial present value of credited projected benefits and is independent of the funding method used to determine contributions to the plans.

The Pension Benefit Obligation was determined by an actuarial valuation performed as of January 1 of each of the years presented. Significant actuarial assumptions used in the valuation include a weighted-average discount rate of 7.0% in 1999 and 1998 and 7.5% in 1997 and projected salary increases of 4.0% in 1999 and 1998 and 5.5% in 1997. The Pension Benefit Obligation for both plans is as follows:

	Amounts as of January 1,		
(In Thousands)	1999	1998	1997
Retirees currently receiving benefits and terminated employees not yet receiving benefits	$1,018	$ 582	$ 384
Current Employees:			
Vested	3,374	3,891	3,295
Non-vested	2,536	2,775	3,081
Total Pension Benefit Obligation	6,928	7,248	6,760
Net assets available for benefits, at market	7,735	7,264	5,898
Under (Over) funded Pension Benefit Obligation	$ (807)	$ (16)	$ 862

MMWEC makes annual contributions to the pension plans equal to the amounts recorded as pension expense, which were $541,000, $498,000 and $896,000, for the years ended December 31, 1999, 1998 and 1997, respectively. The union plan uses the aggregate actuarial cost method and the non-union plan uses the frozen initial liability actuarial cost method in determining pension expense. In addition to the actuarial assumptions outlined above, the assumed long-term rate of return used in determining pension expense was 8.5% in 1999, 1998 and 1997. Pension costs applicable to prior years' service are amortized over thirty years.

MMWEC contributes to an employee savings plan administered by an insurance company. All full-time employees meeting the service requirements are eligible to participate in this defined contribution plan. Under the provisions of the plan, MMWEC's contributions vest immediately. MMWEC contributed $99,000, $99,000 and $114,000 while the employees contributed $177,000, $169,000 and $184,000 during the years ended December 31, 1999, 1998 and 1997, respectively.

(9) Commitments and Contingencies

Power Purchases

MMWEC entered into agreements for participation in the transmission interconnection between New England utilities and the Hydro-Quebec electric system near Sherbrooke, Quebec (Phase I), which began commercial operation in October 1986. The New England portion of the interconnection was constructed at a total cost of about $140 million, of which 3.65% or $5 million is MMWEC's share to support. MMWEC also entered into similar agreements for participation in the interconnection between New England utilities and the Hydro-Quebec electric system for the expansion of the Hydro-Quebec interconnection (Phase II), which went into commercial operation in November 1990. MMWEC's Phase II equity investment approximates 0.6% or $3.3 million. MMWEC has corresponding agreements with certain of its members and another utility to recover MMWEC's share of the costs associated with the interconnection.

Power Sales Agreements

MMWEC sells the Project Capability of each of its Projects to certain of its members and other utilities (Project Participants) under PSAs.

In 1988, the Vermont Supreme Court ruled that the Project No. 6 PSAs between MMWEC and the Vermont Project Participants were void since inception. Consequently, pursuant to the PSAs, MMWEC increased the remaining Project No. 6 Participants pro rata shares of Project Capability to cover the shortfall (step-up), which action was challenged by certain Massachusetts Participants. The Supreme Judicial Court (SJC) for the Commonwealth of Massachusetts in MMWEC et. al. v. Town of Danvers et. al. noted that "the Project 6 PSAs executed by the defendants are valid and that the step-up provisions therein have been properly invoked".

MMWEC is involved in various legal actions. Based on bond counsels' opinions regarding the validity of the PSAs and general counsel representations regarding the litigation, discussions with such counsel, and other considerations, management believes that the ultimate resolution of such litigation will not have a material, adverse effect on the financial position of MMWEC.

In November 1997, the Commonwealth of Massachusetts enacted legislation to restructure the electric utility industry. MMWEC and the municipal light departments are not specifically subjected to the legislation. However, it is management's belief that industry restructuring and customer choice, promulgated within the legislation, will have an effect on MMWEC and the Participant's operations.

Other Issues

The Price-Anderson Act (the Act), a federal statute amended in 1988 to extend to the year 2002, mandates an industry-wide program of liability insurance for nuclear facilities. The Act now provides approximately $6.1 billion for public liability claims from a single incident at a nuclear facility. The $200 million primary layer of insurance for the liability has been purchased in the commercial market. Secondary coverage of $9.9 billion is to be provided through an $88.1 million per incident assessment of each of the currently licensed nuclear units in the United States. The maximum assessment is $10 million per incident per unit in any year. The maximum assessment is subject to adjustment for inflation every five years. MMWEC's interest in Millstone Unit 3 and Seabrook Station could result in a maximum assessment of $4.2 and $10.2 million, limited to payments of $480,000 and $1.2 million per incident per year, respectively.

Insurance has been purchased from Nuclear Electric Insurance Limited (NEIL) to cover the cost of repair, replacement, decontamination or premature decommissioning of utility property resulting from insured occurrences at Millstone Unit 3 and Seabrook Station. The system is subject to retroactive assessments if losses exceed the accumulated funds available to the insurer. MMWEC is potentially subject to a $.5 and $1.7 million assessment for its participation in Millstone Unit 3 and Seabrook Station, respectively, for excess property damage, decontamination and premature decommissioning.

MMWEC is not currently covered under gradual pollution liability insurance related to MMWEC's Stony Brook power plant. Nothing has come to management's attention concerning any material pollution liability claims made during 1999 or outstanding as of December 31, 1999.

MMWEC has established a trust fund to enhance its Directors' and Officers' liability coverage. The purpose of the fund is to make available funds for the purchase of Directors' and Officers' liability insurance or indemnification of the Directors or Officers.

(10) Year 2000 (Unaudited)

In 1998, MMWEC initiated a comprehensive plan (Plan) to identify, assess and remediate "Year 2000"issues within each of its significant computer hardware and software systems and certain equipment containing micro-processors. The Plan addressed the issue of computer systems and embedded computer chips that may be unable to distinguish between the year 1900 and the year 2000 at the change of the millennium. MMWEC divided the Plan into five major phases – inventory, assessment, remediation, testing and validation and contingency planning. MMWEC completed the assessment, planning, remediation, implementation and testing phases. Computer systems and equipment that were not Year 2000 ready were replaced or reprogrammed.

MMWEC identified and contacted critical third party vendors and contractors regarding their plans and progress in addressing their Year 2000 issues. Electronic data interchanges with third parties were reviewed for Year 2000 readiness. MMWEC received varying information from such third parties on the state of readiness or expected readiness. Contingency plans were developed by MMWEC to mitigate Year 2000-induced operational vulnerabilities.

MMWEC has not experienced any material Year 2000 problems or disruptions in its systems or operations, and the costs incurred in addressing Year 2000 compliance have not been material. There can be no assurance, however, that MMWEC will not experience Year 2000 problems that may have a material or adverse effect on the Company's operations, liquidity and financial condition.

Independent Auditors' Report on Supplementary Information

The Board of Directors

Massachusetts Municipal Wholesale Electric Company

We have audited and reported separately herein on the financial statements of Massachusetts Municipal Wholesale Electric Company as of and for the years ended December 31, 1999, 1998 and 1997.

Our audits were made for the purpose of forming an opinion on the basic financial statements of the Massachusetts Municipal Wholesale Electric Company taken as a whole. The supplementary information included in Schedules I through III is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such supplementary information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

KPMG LLP

March 10, 2000

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

Project Statements Of Financial Position

Year Ended December 31, 1999

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
ASSETS				
Electric Plant				
In Service	$ 2,605	$ 60,133	$130,048	$259,630
Accumulated Depreciation	(2,298)	(23,653)	(53,259)	(83,971)
	307	36,480	76,789	175,659
Nuclear Fuel-Net of Amortization	—	1,048	1,904	2,548
Total Electric Plant	307	37,528	78,693	178,207
Special Funds				
Bond Fund				
Interest, Principal and Retirement Account	—	3,326	3,643	8,134
Reserve Account	—	6,845	11,299	14,063
Reserve and Contingency Fund	—	3,461	3,959	5,021
Revenue Fund	—	4,895	6,205	10,871
Working Capital Funds	19,993	—	—	—
	19,993	18,527	25,106	38,089
Current Assets				
Cash and Temporary Investments	1,036	—	—	1
Accounts Receivable	5,936	35	40	137
Unbilled Revenues	3,300	—	—	—
Inventories	—	59	—	1,578
Advances to (from) Projects	2,146	(255)	(464)	(158)
Prepaid Expenses	566	867	1,627	1,273
Total Current Assets	12,984	706	1,203	2,831
Total Special Funds and Current Assets	32,977	19,233	26,309	40,920
Deferred Charges				
Amounts Recoverable (Payable) Under Terms of the Power Sales Agreements	36,371	61,390	87,437	2,593
Unamortized Debt Discount and Expenses	324	1,788	2,868	4,661
Nuclear Decommissioning Trusts	—	2,818	5,336	3,786
Other	18	163	258	661
	36,713	66,159	95,899	11,701
	$69,997	$122,920	$200,901	$230,828
LIABILITIES				
Long-Term Debt				
Bonds Payable	$ —	$110,465	$184,670	$212,360
Current Liabilities				
Current Maturities of Long-Term Debt	—	5,825	6,895	6,820
Commercial Paper	36,765	—	—	—
Notes Payable	82	—	—	—
Accounts Payable	1,308	130	157	1,357
Accrued Expenses	5,182	1,843	3,386	4,036
Member and Participant Advances and Reserves	26,660	1,760	312	2,312
	69,997	9,558	10,750	14,525
Deferred Credits	—	2,897	5,481	3,943
	$69,997	$122,920	$200,901	$230,828

Schedule I

Nuclear Proj. 5	Project No. 6	Peaking	Intermediate	Wyman	Hydro Quebec Phase II	Total
$ 71,038	$ 501,688	$ 56,380	$ 151,337	$ 7,341	$ —	$1,240,200
(23,060)	(164,514)	(38,230)	(106,860)	(4,544)	—	(500,389)
47,978	337,174	18,150	44,477	2,797	—	739,811
648	3,588	—	—	—	—	9,736
48,626	340,762	18,150	44,477	2,797	—	749,547
2,451	18,810	2,534	6,236	293	—	45,427
4,381	32,428	2,408	6,196	284	—	77,904
1,336	7,603	844	1,606	283	—	24,113
2,921	18,899	7,164	21,192	1,478	—	73,625
—	—	—	—	—	(20)	19,973
11,089	77,740	12,950	35,230	2,338	(20)	241,042
—	2	—	—	—	42	1,081
35	189	—	41	67	100	6,580
—	—	—	—	—	—	3,300
399	2,186	3,512	10,609	162	—	18,505
(52)	(279)	(224)	(684)	(30)	—	—
324	1,769	13	22	9	—	6,470
706	3,867	3,301	9,988	208	142	35,936
11,795	81,607	16,251	45,218	2,546	122	276,978
6,187	44,200	(5,099)	6,933	(648)	(799)	238,565
1,825	9,929	131	927	(5)	—	22,448
958	5,244	—	—	—	—	18,142
170	957	34	3,227	37	783	6,308
9,140	60,330	(4,934)	11,087	(616)	(16)	285,463
$ 69,561	$ 482,699	$ 29,467	$ 100,782	$ 4,727	$ 106	$1,311,988
$ 64,635	$ 449,860	$ 23,020	$ 81,375	$ 3,830	$ —	$1,130,215
1,925	13,935	3,720	8,390	360	—	47,870
—	—	—	—	—	—	36,765
—	—	—	—	—	—	82
344	1,880	1,005	3,484	188	7	9,860
1,024	5,622	51	352	5	—	21,501
635	5,941	1,671	7,181	344	99	46,915
3,928	27,378	6,447	19,407	897	106	162,993
998	5,461	—	—	—	—	18,780
$ 69,561	$ 482,699	$ 29,467	$ 100,782	$ 4,727	$ 106	$1,311,988

Project Statements of Operations

Year Ended December 31, 1999

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
Revenues	$ 41,447	$16,839	$27,360	$30,111
Interest Income	1,370	1,359	1,714	2,509
Total Revenues and Interest Income	$ 42,817	$18,198	$29,074	$32,620
Operating and Service Expenses:				
Fuel Used in Electric Generation	$ —	$ 675	$ 1,212	$ 1,829
Purchased Power	36,860	—	—	—
Other Operating	1,606	4,059	7,355	7,426
Maintenance	21	1,465	2,749	2,291
Depreciation	32	1,957	4,126	9,417
Taxes Other Than Income	4	435	790	1,048
	38,523	8,591	16,232	22,011
Interest Expense:				
Interest Charges	782	5,872	10,316	12,427
Interest Charged to Projects During Construction	—	(2)	(7)	(3)
	782	5,870	10,309	12,424
Total Operating Costs and Interest Expense	39,305	14,461	26,541	34,435
Other	18,874	—	—	—
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements	(15,362)	3,737	2,533	(1,815)
	$ 42,817	$18,198	$29,074	$32,620

* *Allocation between Maintenance and Other Operating is not available.*

Schedule II

Nuclear Proj. 5	Project No. 6	Peaking	Intermediate	Wyman	Hydro Quebec Phase II	Total
$8,549	$56,948	$7,982	$39,546	$2,791	$521	$232,094
668	4,820	751	2,016	142	60	15,409
$9,217	$61,768	$8,733	$41,562	$2,933	$581	$247,503
$465	$ 2,588	$1,684	$18,135	$1,702	$ —	$ 28,290
—	—	—	—	—	560	37,420
1,937	10,647	1,298	4,536	*503	—	39,367
580	3,174	178	4,749	—	—	15,207
2,574	18,118	2,273	6,304	231	—	45,032
265	1,451	390	1,078	184	—	5,645
5,821	35,978	5,823	34,802	2,620	560	170,961
3,921	29,052	1,500	4,732	194	—	68,796
(1)	(6)	—	—	—	—	(19)
3,920	29,046	1,500	4,732	194	—	68,777
9,741	65,024	7,323	39,534	2,814	560	239,738
—	—	—	—	—	—	18,874
(524)	(3,256)	1,410	2,028	119	21	(11,109)
$9,217	$61,768	$8,733	$41,562	$2,933	$581	$247,503

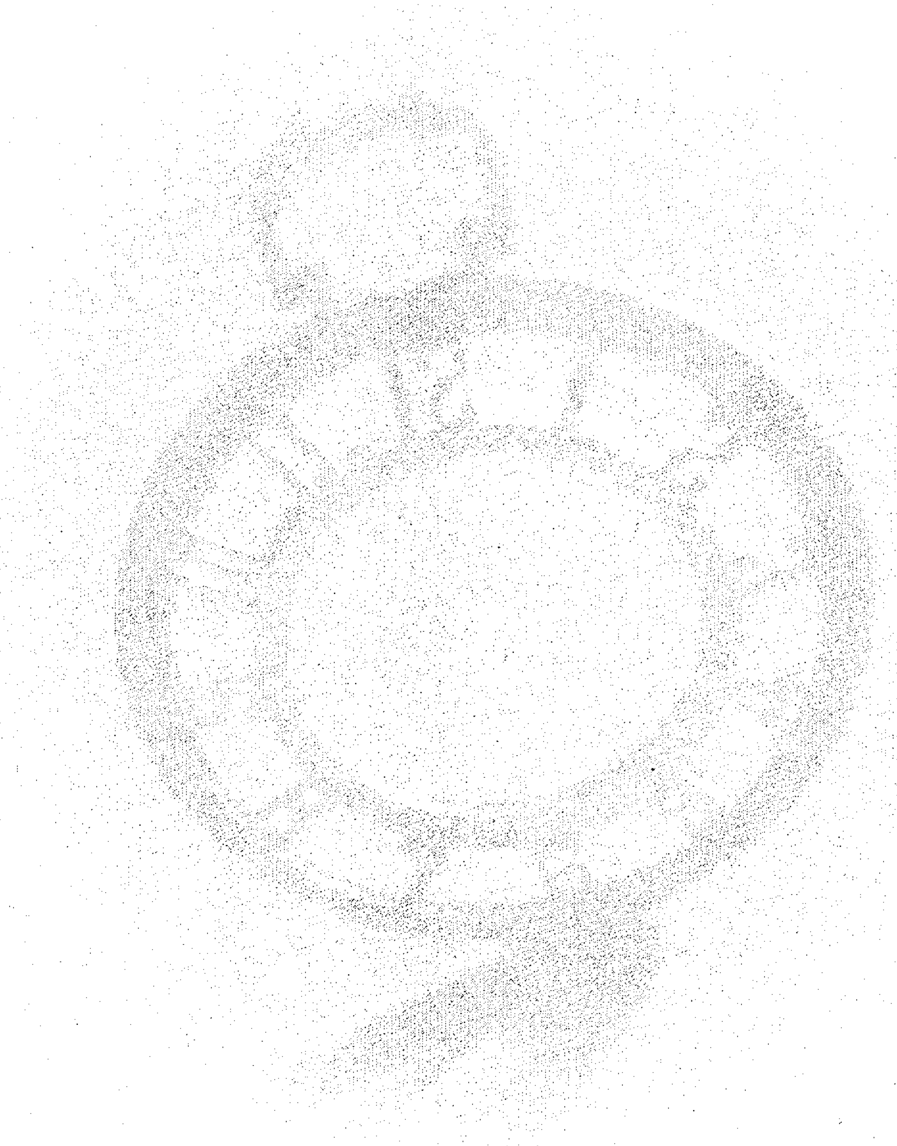
Project Statements of Cash Flows

Year Ended December 31, 1999

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
Cash flows from operating activities:				
Total Revenues and Interest Income	$ 42,817	$ 18,198	$ 29,074	$ 32,620
Total Costs and Expenses, net	(58,179)	(14,461)	(26,541)	(34,435)
Adjustments to arrive at net cash provided by operating activities:				
Depreciation and Decommissioning	32	2,222	4,603	10,103
Amortization	67	742	1,277	1,909
Change in current assets and liabilities:				
Accounts Receivable	(1,197)	(16)	2	(130)
Unbilled Revenues	476	—	—	—
Inventories	—	(1)	—	(37)
Prepaid Expenses	39	145	246	586
Accounts Payable	(2,528)	95	170	326
Accrued Expenses and Other	(379)	258	787	1,026
Member and Participant Advances and Reserves	(3,264)	(348)	(1,825)	(917)
Net cash provided by (used for) operating activities	(22,116)	6,834	7,793	11,051
Cash flows from investing activities:				
Construction Expenditures and Purchases of Nuclear Fuel	(129)	(876)	(1,658)	(1,188)
Interest Charged to Projects During Construction	—	(2)	(7)	(3)
Net (Increase) Decrease in Special Funds	5,935	129	461	(1,937)
Change in net Unrealized Gain (Loss) on Special Funds	(58)	(226)	(431)	(743)
Decommissioning Trust Payments	—	(400)	(732)	(871)
Other	188	126	239	186
Net cash provided by (used for) investing activities	5,936	(1,249)	(2,128)	(4,556)
Cash flows from financing activities:				
Payments for Principal of Long-Term Debt and Commercial Paper	(3,580)	(5,585)	(5,665)	(6,495)
Proceeds from Commercial Paper	19,140	—	—	—
Payments for Commercial Paper Issue Costs	(143)	—	—	—
Change in Notes Payable	82	—	—	—
Net cash provided by (used for) financing activities	15,499	(5,585)	(5,665)	(6,495)
Net increase (decrease) in cash and temporary investments	(681)	—	—	—
Cash and Temporary Investments at Beginning of Year	1,717	—	—	1
Cash and Temporary Investments at End of Year	$ 1,036	$ —	$ —	$ 1
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 640	$ 5,612	$ 9,922	$ 11,910

Schedule III

Nuclear Proj. 5	Project No. 6	Peaking	Intermediate	Wyman	Hydro Quebec Phase II	Total
$ 9,217	$ 61,768	$ 8,733	$ 41,562	$ 2,933	$ 581	$ 247,503
(9,741)	(65,024)	(7,323)	(39,534)	(2,814)	(560)	(258,612)
2,747	19,068	2,256	6,239	232	—	47,502
546	3,003	48	236	1	—	7,829
(33)	(179)	78	1,620	(53)	6	98
—	—	—	—	—	—	476
(9)	(51)	(1,290)	(3,372)	2	—	(4,758)
148	812	—	(1)	43	—	2,018
92	497	1,178	2,415	95	6	2,346
314	1,757	43	(366)	(3)	(24)	3,413
(202)	(2,122)	278	2,800	(59)	36	(5,623)
3,079	19,529	4,001	11,599	377	45	42,192
(301)	(1,644)	(41)	(199)	(1)	—	(6,037)
(1)	(6)	—	—	—	—	(19)
(559)	(2,074)	(304)	(3,135)	(10)	(1)	(1,495)
(210)	(1,690)	(126)	(280)	(21)	—	(3,785)
(221)	(1,205)	—	—	—	—	(3,429)
47	256	—	45	—	—	1,087
(1,245)	(6,363)	(471)	(3,569)	(32)	(1)	(13,678)
(1,835)	(13,165)	(3,530)	(8,030)	(345)	—	(48,230)
—	—	—	—	—	—	19,140
—	—	—	—	—	—	(143)
—	—	—	—	—	—	82
(1,835)	(13,165)	(3,530)	(8,030)	(345)	—	(29,151)
(1)	1	—	—	—	44	(637)
1	1	—	—	—	(2)	1,718
$ —	$ 2	$ —	$ —	$ —	$ 42	$ 1,081
$ 3,727	$ 28,003	$ 1,421	$ 4,461	$ 189	$ —	$ 65,885



Copies of this report and supplemental financial information can be obtained, free of charge, by writing to the Public Affairs/Corporate Communications Office, Massachusetts Municipal Wholesale Electric Company, P.O. Box 426, Ludlow, MA 01056. Phone: (413) 589-0141; Fax: (413) 589-1585; E-mail: mmwec@mmwec.org; Internet: www.mmwec.org.

All requests for information about MMWEC should be directed to this office.

Annual Report 1999

New England Power Company

National Grid

New England Power Company
25 Research Drive
Westborough, Massachusetts 01582

Directors
(As of March 22, 2000)

Cynthia A. Arcate
Vice President of the Company

L. Joseph Callan
Former Executive Director for Operations, Nuclear Regulatory Commission

Peter G. Flynn
President of the Company

Alfred D. Houston
Chairman of the Company and Former Chairman of New England Electric System

Cheryl A. LaFleur
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of National Grid USA

Richard P. Sergel
President and Chief Executive Officer of National Grid USA

Philip R. Sharp
Lecturer, Harvard University, John F. Kennedy School of Government

Officers
(As of March 22, 2000)

Alfred D. Houston
Chairman of the Company and Former Chairman of New England Electric System

Peter G. Flynn
President of the Company

Michael E. Jesanis
Vice President of the Company and Senior Vice President and Chief Financial Officer of National Grid USA

Cheryl A. LaFleur
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of National Grid USA

Cynthia A. Arcate
Vice President of the Company

John F. Malley
Vice President of the Company

Masheed H. Rosenqvist
Vice President of the Company and of certain affiliates

James S. Robinson
Vice President of the Company

Gregory A. Hale
Clerk of the Company and of certain affiliates, Assistant Secretary or Assistant Clerk of certain affiliates and Secretary of an affiliate

John G. Cochrane
Treasurer of the Company and of certain affiliates, Vice President of an affiliate, Assistant Treasurer of an affiliate and Vice President and Treasurer of National Grid USA

Kirk L. Ramsauer
Assistant Clerk of the Company and of certain affiliates, Secretary or Clerk of certain affiliates and Assistant Secretary of an affiliate

Kwong O. Nuey
Controller of the Company and of certain affiliates

Transfer Agent, Dividend Paying Agent, and Registrar of Preferred Stock
BankBoston, N.A., Boston, Massachusetts

New England Power Company

New England Power Company, (the Company) a wholly owned subsidiary of National Grid USA (formerly New England Electric System), is a Massachusetts corporation qualified to do business in Massachusetts, New Hampshire, Rhode Island, Connecticut, Maine, and Vermont. The Company is subject, for certain purposes, to the jurisdiction of the regulatory commissions of these six states, the Securities and Exchange Commission, under the Public Utility Holding Company Act of 1935, the Federal Energy Regulatory Commission, and the Nuclear Regulatory Commission. The Company's business is primarily the transmission of electric energy in wholesale quantities to other electric utilities, principally its distribution affiliates Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company, and The Narragansett Electric Company. The Company's transmission business will also do business under the name of National Grid Transmission USA.

Report of Independent Accountants

New England Power Company, Westborough, Massachusetts:

In our opinion, the accompanying balance sheets and the related statements of income, of retained earnings, and cash flows present fairly, in all material respects, the financial position of New England Power Company (the Company), a wholly owned subsidiary of National Grid USA (formerly New England Electric System), at December 31, 1999 and 1998, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States. 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 of these statements in accordance with auditing standards generally accepted in the United States which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP
Boston, Massachusetts

March 6, 2000, except for Note B,
as to which the date is March 22, 2000

New England Power Company
Financial Review

Merger Agreement with National Grid

On March 22, 2000, the merger of New England Electric System (NEES) and The National Grid Group plc (National Grid) was completed, with NEES (renamed National Grid USA) becoming a wholly owned subsidiary of National Grid. New England Power Company (the Company) will maintain its existing name and will remain a wholly owned subsidiary of National Grid USA. The merger is being accounted for by the purchase method, the application of which, including the recognition of goodwill, is being pushed down and reflected on the books of the National Grid USA subsidiaries, including the Company.

Merger Agreement with EUA

In February 1999, NEES, Eastern Utilities Associates (EUA), and Research Drive LLC (Research Drive), a wholly owned subsidiary of NEES, entered into an Agreement and Plan of Merger (EUA Agreement). Pursuant to the EUA Agreement, Research Drive will merge with and into EUA, with EUA becoming a wholly owned subsidiary of National Grid USA.

The acquisition of EUA has received approval or support from EUA shareholders, the Federal Trade Commission (FTC), the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), the Connecticut Department of Public Utility Control, the Rhode Island Public Utilities Commission, the Massachusetts Department of Telecommunications and Energy (MDTE), and the Vermont Public Service Board (VPSB). An application has also been filed for approval with the Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935 (1935 Act). The acquisition of EUA, including the consolidation of Montaup Electric Company (Montaup Electric), a wholly owned subsidiary of EUA, into the Company, is expected to be completed following the receipt of an SEC order approving the acquisition, which could come at any time. If the SEC order is not received in time to close the transaction by April 28, 2000, the approval by the FTC, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, expires and will have to be renewed prior to completion of the acquisition.

Industry Restructuring

Pursuant to legislation enacted in Massachusetts, Rhode Island, and New Hampshire, and settlement agreements approved by state and federal regulators (the Settlement Agreements), customers were granted choice of power supplier in 1998. To facilitate the implementation of customer choice, the Settlement Agreements provided for the termination of the Company's all-requirements contracts with its affiliated distribution companies. The Company's all-requirements contracts with unaffiliated customers were also generally terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service at fixed rates to new customer load in Rhode Island. In addition, as a result of the Settlement Agreements, the Company and its affiliate, The Narragansett Electric Company, sold substantially all of their nonnuclear generating business (divestiture) in September 1998. As part of the divestiture plan, New England Energy Incorporated sold its oil and gas properties in 1998, resulting in a loss of approximately $120 million, before tax, which was reimbursed by the Company. The Company also agreed to endeavor to sell its minority interest in three nuclear power plants and a 60 megawatt interest in a fossil-fueled generating station in Maine.

In conjunction with the divestiture, the Company transferred to the buyer of its nonnuclear generating business (the buyer) its entitlement to power procured under several long-term contracts in exchange for monthly fixed payments by the Company averaging $9.5 million per month through January 2008 (having a net present value at December 31, 1999 of approximately $704 million) toward the above-market cost of those contracts. For certain contracts which have been formally assigned to the buyer, the Company has made lump sum payments equivalent to the present value of the monthly fixed payment obligations of those contracts (approximately $345 million), which were separate from the $704 million figure referred to above.

Under the Settlement Agreements, the Company is permitted to recover costs associated with its former generating investments and related contractual commitments that were not recovered through the sale of those investments ("stranded costs"). These costs are recovered from the Company's wholesale customers through contract termination charges (CTC) which the affiliated wholesale customers recover through delivery charges to distribution customers. The recovery of the Company's stranded costs is divided into several categories. Unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets will be fully recovered through the CTC by the end of 2000 and earn a return on equity averaging 9.7 percent. The Company's obligation related to the above-market cost of purchased power contracts and nuclear decommissioning costs are recovered through the CTC as such costs are actually incurred. As the CTC rate declines, the Company, under certain of the Settlement Agreements, earns incentives based on successful mitigation of its stranded costs. These incentives supplement the Company's return on equity. Until such time as the Company divests its operating nuclear interests, the Company will share with customers, through the CTC, 80 percent of the revenues and operating costs related to the units, with shareholders retaining the balance. For further information on the potential sale of the Vermont Yankee and Millstone 3 nuclear generating units, refer to the "Nuclear Units" section below.

Accounting Implications

Because electric utility rates have historically been based on a utility's costs, electric utilities are subject to certain accounting standards that are not applicable to other business enterprises in general. The Company applies the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71), which requires regulated entities, in appropriate circumstances, to establish regulatory assets, and thereby defer the income statement impact of certain charges or revenues because they are expected to be collected or refunded through future customer billings. In 1997, the Emerging Issues Task Force of the Financial Accounting Standards Board concluded that a utility that had received approval to recover stranded costs through regulated rates would be permitted to continue to apply FAS 71 to the recovery of stranded costs.

As discussed above, the Company received authorization from the FERC to recover through CTCs substantially all of the costs associated with its former generating business not recovered through the divestiture. Additionally, FERC Order No. 888 enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of the Company's business, including the recovery of its stranded costs, remains under cost-based rate regulation. Because of the nuclear cost-sharing provisions related to the Company's CTC, the Company ceased applying FAS 71 in 1997 to 20 percent of its ongoing nuclear operations, the impact of which is immaterial.

As a result of applying FAS 71, the Company has recorded a regulatory asset for the costs that are recoverable from customers through the CTC. At December 31, 1999, this amounted to approximately $1.3 billion, including $1.0 billion related to the above-market costs of purchased power contracts, $0.3 billion related to accrued Yankee nuclear plant costs, and a smaller amount of other net CTC-related regulatory assets.

In 1998, the Company concluded that its interests in the Millstone 3 and Seabrook 1 nuclear generating units had little, if any, market value, based, in part, on the fact that proposed sales of nuclear units by other utilities have required the seller to set aside amounts for decommissioning in excess of the proceeds from the sale of the units. As a result, the Company recorded an impairment write-down in its reserve for depreciation of approximately $390 million, representing the book value of Millstone 3 and Seabrook 1 at December 31, 1995, less applicable depreciation subsequent to that date.

Impact of Mergers on Transmission and CTC Rates

In March 2000, the MDTE approved the merger of Montaup Electric into the Company, which is contingent upon the approval of the pending acquisition of EUA. Under a rate consolidation plan accepted by the FERC in September 1999, upon National Grid USA's acquisition of EUA, Montaup Electric's open access transmission tariffs will adopt the same terms and conditions for service as those contained in the Company's tariffs. Upon the merger of Montaup Electric into the Company, the combined company will charge a single system transmission tariff based upon its total transmission costs. The CTC rates for the companies will not initially be combined.

Overview of Financial Results

Net income for 1999 decreased $52 million compared with 1998 as a result of the continuing impacts of the divestiture and the restructuring of the utility business. Partially offsetting the decrease is the recovery of stranded cost mitigation incentives of approximately $25 million in 1999 compared with $10 million in 1998, as well as increased transmission revenues of approximately $13 million due to the elimination of certain liabilities related to open access transmission tariffs.

Net income for 1998 decreased $22 million compared with 1997. This decrease was also primarily due to the divestiture and reduced revenues as a result of industry restructuring.

Operating Revenue

Operating revenue for 1999 decreased $622 million compared with 1998 due to the divestiture and reduced CTC charges. Partially offsetting these decreases is an increase in transmission revenues associated with the elimination of certain liabilities related to open access transmission tariffs discussed above.

Operating revenue for 1998 decreased $460 million compared with 1997. This decrease was also the result of the divestiture and reduced revenues due to industry restructuring, partially offset by the recovery of stranded investments and increased transmission billings.

Operating Expenses

Operating expenses for 1999 decreased $543 million compared with 1998. The divestiture reduced all categories of operating expenses in 1999, with the exception of depreciation and amortization expenses.

The decrease in fuel expense and purchased power costs reflects the divestiture and the assumption of the Company's obligations under most of its previously existing purchased power contracts by the buyer of its nonnuclear generating business. The Company remains obligated to pay predetermined amounts to the buyer related to the above-market cost of those contracts. In addition, the Company also remains obligated under purchased power contracts with the four Yankee nuclear power companies, the costs of which decreased $8 million in 1999, reflecting reduced costs from Maine Yankee and Connecticut Yankee, net of increased costs of a 1999 refueling outage at Vermont Yankee.

In addition to the impact of the divestiture, which reduced nonnuclear generation operation and maintenance expenses by $71 million, the decrease in other operation and maintenance expenses reflects reduced general and administrative costs due primarily to workforce reductions and reduced charges from New England Power Service Company following the divestiture. In addition, transmission costs decreased $16 million in 1999 due to the assumption of transmission support agreements by the buyer and reduced Independent System Operator-New England start-up costs. These decreases were partially offset by increased costs of $3 million associated with the partially owned Millstone 3 and Seabrook 1 nuclear generating facilities which experienced refueling outages in the second quarter of 1999.

Operating expenses for 1998 decreased $426 million compared with 1997 as a result of the divestiture, reduced charges of $22 million from Maine Yankee, which was closed in mid-1997, and reduced charges of $3 million and $12 million from the partially owned Seabrook 1 and Millstone 3 nuclear generating facilities, respectively. Operating expenses also decreased due to lower charges related to postretirement benefits other than pensions (PBOPs), reflecting the completion of the accelerated amortization of the Company's deferred PBOP costs in 1997 under the terms of a 1995 rate agreement.

Depreciation and amortization expenses increased $3 million and $2 million in 1999 and 1998, respectively, due to the recovery and amortization of generation-related stranded costs in those years being greater than the depreciation and amortization of generation-related plant in the prior years. The increase is also due to new transmission plant expenditures.

Interest Expense and Other Income

The decrease in interest expense in 1999 and 1998 was principally due to reduced long-term and short-term debt as a result of the divestiture.

The increase in other income in 1999 and 1998 was due primarily to increased interest income resulting from the reinvestment of the proceeds from the divestiture. In 1999, this was partially offset by reduced equity income from nuclear power companies as a result of reductions in the rates of return for two of these companies.

Nuclear Units

Nuclear Units Permanently Shut Down

Three regional nuclear generating companies in which the Company has a minority interest own nuclear generating units that have been permanently shut down. These three units are as follows:

Unit	The Company's Investment %	The Company's Investment $ (millions)	Date Retired	Future Estimated Billings to the Company $ (millions)
Yankee Atomic	30	5	Feb 1992	7
Connecticut Yankee	15	16	Dec 1996	63
Maine Yankee	20	15	Aug 1997	128

In the case of each of these units, the Company has recorded a liability and an offsetting regulatory asset reflecting the estimated future billings from the companies. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant, including a return on that investment, as well as unfunded nuclear decommissioning costs and other costs. Maine Yankee recovers its costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999. Connecticut Yankee filed a similar request with the FERC, to which several parties intervened in opposition. In August 1998, a FERC Administrative Law Judge (ALJ) issued an initial decision which would allow for full recovery of Connecticut Yankee's unrecovered investment, but precluded a return on that investment. Connecticut Yankee, the Company, and other parties filed with the FERC exceptions to the ALJ's decision. Should the FERC uphold the ALJ's initial decision in its current form, the Company's share of the loss of the return component would total approximately $12 million to $15 million before taxes for the entire recovery period.

A Maine statute provides that if both Maine Yankee and its decommissioning trust fund have insufficient assets to pay for the plant decommissioning, the owners of Maine Yankee are jointly and severally liable for the shortfall.

Under the provisions of the Settlement Agreements, the Company recovers all costs, including shutdown costs, that the FERC allows these Yankee companies to bill to the Company.

Operating Nuclear Units

The Company has minority interests in three operating nuclear generating units which the Company is engaged in efforts to divest: Vermont Yankee, Millstone 3, and Seabrook 1. Uncertainties regarding the future of nuclear generating stations, particularly older units, such as Vermont Yankee, have increased in recent years and could adversely affect their service lives, availability, and costs. These uncertainties stem from a combination of factors, including the acceleration of competitive pressures in the power generation industry and increased NRC scrutiny. The Company performs periodic economic viability reviews of operating nuclear units in which it holds ownership interests.

Vermont Yankee

The following table summarizes the Company's interests in the Vermont Yankee Nuclear Power Corporation:

	(millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
20	11	34	86	42	2012

In November 1999, the Vermont Yankee Nuclear Power Corporation entered into an agreement with AmerGen Energy Company (AmerGen), a joint venture between PECO Energy and British Energy, to sell the assets of Vermont Yankee. Under the terms of the agreement, after a Vermont Yankee contribution toward the plant's decommissioning trust fund, AmerGen will take over the fund and assume responsibility for the actual cost of decommissioning the plant. The agreement also requires the existing power purchasers (including the Company) to continue to purchase the output of the plant or to buy out of the purchased power obligation. In November 1999, the Company signed an agreement to buy out of its obligation, requiring future payments which will be recovered through the Company's CTC. The Company has recorded an accrued liability and offsetting regulatory asset of $80 million for its share of future liabilities related to Vermont Yankee, including the purchased power contract termination payment obligation, but excluding interest and a return allowance. The proposed sale is contingent upon regulatory approvals by the NRC, the SEC, under the 1935 Act, and the VPSB, among others.

Millstone 3

In July 1998, Millstone 3, which is operated by a subsidiary of Northeast Utilities (NU), returned to full operation after being shut down for more than two years.

In August 1997, the Company sued NU in Massachusetts Superior Court for damages resulting from the tortious conduct of NU that caused the shutdown of Millstone 3. The Company's claim for damages included the costs of replacement power during the outage, costs necessary to return Millstone 3 to safe operation, and other additional costs. Most of the Company's incremental replacement power costs have been recovered from customers, either through fuel adjustment clauses or through provisions in the Settlement Agreements.

In August 1997, the Company also sent a demand for arbitration to Connecticut Light & Power Company and Western Massachusetts Electric Company, both subsidiaries of NU (subsidiaries), seeking damages resulting from their breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3.

In November 1999, the Company, NU, and the subsidiaries executed an agreement which settled the litigation and arbitration described above. Under the settlement, NU paid the Company approximately $24 million. In addition, NU also agreed to include the Company's Millstone 3 interest when NU sells its Millstone 3 interest at auction. Amounts received pursuant to a sale will, after reimbursement of the Company's transaction costs and net investment in Millstone 3, be credited to customers.

Year 2000 Disclosure

In 1999, the NEES companies completed their remediation of the information systems (computer) problem resulting from the fact that many software applications and operational programs written in the past might not have recognized calendar dates associated with the year 2000 (Y2K). As a result of their remediation efforts, the NEES companies have experienced no significant disruptions in any of their enterprise or operational computer systems.

The NEES companies' costs of making the necessary Y2K modifications were approximately $28 million. In addition, the NEES companies spent approximately $9 million (of which approximately $7 million has been capitalized) related to the replacement of the human resources and payroll system, in part due to the Y2K issue.

Risk Management

The Company's major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable rate debt. At December 31, 1999, the Company's variable rate long-term debt had a carrying value and fair value of approximately $372 million, a weighted average interest rate of 3.73 percent, and maturity dates of greater than five years.

As discussed in the "Industry Restructuring" section, the Company remains obligated to provide transition power supply service at fixed rates to new customer load in Rhode Island. The Company meets these obligations by periodically procuring the necessary power supply at market prices. The Company cannot predict whether the resulting revenues will be sufficient to cover the costs to procure such power.

Utility Plant Expenditures and Financing

Cash expenditures for utility plant totaled $57 million in 1999 and were primarily transmission-related. The funds necessary for utility plant expenditures during the period were primarily provided by internal funds. Cash expenditures for 2000 are estimated to be approximately $45 million, principally related to transmission functions. Internally generated funds are expected to fully cover the Company's capital expenditures in 2000.

On February 8, 1999, the Company repurchased 130,000 shares of its common stock from NEES for $18 million. Approximately $7 million of the repurchase price was charged to retained earnings.

On November 30, 1999, the Company declared a dividend of approximately $232 million, payable on September 30, 2000, to the shareholders of record on September 29, 2000.

In 1999, the Company increased its short-term debt outstanding by $39 million. The Company has regulatory approval from the SEC, under the 1935 Act, to issue up to $375 million of short-term debt. The Company plans to seek the necessary regulatory approvals in 2000 which would allow the $39 million of variable rate debt to remain outstanding through 2015. This would result in classifying the debt as long-term rather than short-term.

At December 31, 1999, the Company had lines of credit and standby bond purchase facilities with banks totaling $460 million which are available to provide liquidity support for $410 million of the Company's short-term and long-term bonds in tax-exempt commercial paper mode (including the $39 million discussed above), and for other corporate purposes. There were no borrowings under these lines of credit at December 31, 1999.

New England Power Company

Statements of Income

Year ended December 31 (In thousands)	1999	1998	1997
Operating revenue, principally from affiliates	**$ 596,341**	$1,218,340	$ 1,677,903
Operating expenses:			
Fuel for generation	**12,803**	223,828	372,734
Purchased electric energy:			
Contract termination and nuclear unit shutdown charges	**187,777**	97,469	43,876
Other	**56,731**	302,367	483,771
Other operation	**70,936**	155,065	241,506
Maintenance	**28,536**	60,239	89,820
Depreciation and amortization	**103,080**	99,924	98,024
Taxes, other than income taxes	**20,282**	48,492	67,311
Income taxes	**37,633**	73,594	90,009
Total operating expenses	**517,778**	1,060,978	1,487,051
Operating income	**78,563**	157,362	190,852
Other income:			
Allowance for equity funds used during construction	**1,958**	633	-
Equity in income of nuclear power companies	**2,939**	5,284	5,189
Other income (expense), net	**2,087**	118	(3,404)
Operating and other income	**85,547**	163,397	192,637
Interest:			
Interest on long-term debt	**14,052**	30,775	42,277
Other interest	**1,003**	10,688	7,055
Allowance for borrowed funds used during construction	**(522)**	(961)	(1,238)
Total interest	**14,533**	40,502	48,094
Net income	**$ 71,014**	$ 122,895	$ 144,543

Statements of Retained Earnings

Year ended December 31 (In thousands)	1999	1998	1997
Retained earnings at beginning of year	**$ 204,603**	$ 407,630	$ 400,610
Net income	**71,014**	122,895	144,543
Dividends declared on cumulative preferred stock	**(94)**	(1,230)	(2,075)
Dividends declared on common stock, $37.43, $20.25, and $21.00 per share, respectively	**(241,415)**	(130,610)	(135,448)
Premium on redemption of preferred stock	**264**	(264)	-
Repurchase of common stock	**(7,085)**	(193,818)	-
Retained earnings at end of year	**$ 27,287**	$ 204,603	$ 407,630

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

New England Power Company

Balance Sheets

At December 31 (In thousands)	1999	1998
Assets		
Utility plant, at original cost	$ 1,312,384	$ 1,262,461
Less accumulated provisions for depreciation and amortization	849,694	837,637
	462,690	424,824
Construction work in progress	30,063	33,289
Net utility plant	492,753	458,113
Investments:		
Nuclear power companies, at equity (Note D-1)	46,233	48,538
Decommissioning trust funds (Note D-2)	36,279	31,281
Nonutility property and other investments	7,248	8,302
Total investments	89,760	88,121
Current assets:		
Cash and temporary cash investments (including $59,039 and $109,911 with affiliates)	204,344	179,413
Accounts receivable:		
Affiliated companies	73,444	107,878
Others	44,301	32,573
Fuel, materials, and supplies, at average cost	9,471	9,220
Prepaid and other current assets	39,315	21,569
Total current assets	370,875	350,653
Regulatory assets (Note C)	1,345,832	1,512,562
Deferred charges and other assets	3,445	5,339
	$ 2,302,665	$ 2,414,788
Capitalization and Liabilities		
Capitalization:		
Common stock, par value $20 per share, Authorized - 6,449,896 shares Outstanding - 3,619,896 and 3,749,896 shares	$ 72,398	$ 74,998
Premium on capital stock	48,623	50,371
Other paid-in capital	183,937	190,852
Retained earnings	27,287	204,603
Unrealized gain on securities, net	91	72
Total common equity	332,336	520,896
Cumulative preferred stock, par value $100 per share (Note H)	1,567	1,567
Long-term debt	371,771	371,765
Total capitalization	705,674	894,228
Current liabilities:		
Short-term debt	38,500	-
Accounts payable (including $25,620 and $119,657 to affiliates)	63,212	162,360
Accrued liabilities:		
Taxes	3,889	15,009
Interest	3,378	2,440
Other accrued expenses (Note G)	15,693	20,086
Dividends payable	232,365	24
Total current liabilities	357,037	199,919
Deferred federal and state income taxes	179,686	165,115
Unamortized investment tax credits	19,060	30,870
Accrued Yankee nuclear plant costs (Note D-2)	277,932	242,138
Purchased power obligations	703,737	832,668
Other reserves and deferred credits	59,539	49,850
Commitments and contingencies (Note D)		
	$ 2,302,665	$ 2,414,788

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

New England Power Company

Statements of Cash Flows

Year ended December 31 (In thousands)	1999	1998	1997
Operating activities:			
Net income	**$ 71,014**	$ 122,895	$ 144,543
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**108,789**	104,331	101,186
Deferred income taxes and investment tax credits, net	**14,111**	(226,722)	(12,728)
Allowance for funds used during construction	**(2,480)**	(1,594)	(1,238)
Reimbursement to New England Energy Incorporated of loss on sale of oil and gas properties	**-**	(120,900)	-
Buyout of purchased power contracts	**(3,472)**	(326,590)	-
Decrease (increase) in accounts receivable	**22,706**	130,914	(25,128)
Decrease (increase) in fuel, materials, and supplies	**(251)**	(10,270)	11,217
Decrease (increase) in prepaid and other current assets	**(17,746)**	(8,778)	7,213
Increase (decrease) in accounts payable	**(99,148)**	(31,761)	(18,105)
Increase (decrease) in other current liabilities	**(14,575)**	5,037	(1,905)
Other, net	**(3,995)**	(49,611)	19,919
Net cash provided by (used in) operating activities	**$ 74,953**	$ (413,049)	$ 224,974
Investing activities:			
Proceeds from sale of generating assets	**$ -**	$ 1,688,863	$ -
Plant expenditures, excluding allowance for funds used during construction	**(56,887)**	(64,446)	(69,863)
Other investing activities	**(4,411)**	(5,474)	(4,040)
Net cash provided by (used in) investing activities	**$ (61,298)**	$ 1,618,943	$ (73,903)
Financing activities:			
Capital contribution from parent	**$ -**	$ 34,881	$ -
Dividends paid on common stock	**(9,050)**	(166,084)	(127,386)
Dividends paid on preferred stock	**(118)**	(1,206)	(2,075)
Changes in short-term debt	**38,500**	(111,250)	17,650
Long-term debt - retirements	**-**	(328,000)	(38,500)
Repurchase of common shares	**(18,056)**	(417,960)	-
Preferred stock - retirements	**-**	(38,505)	-
Premium on reacquisition of long-term debt	**-**	-	(2,163)
Net cash provided by (used in) financing activities	**$ 11,276**	$ (1,028,124)	$ (152,474)
Net increase (decrease) in cash and cash equivalents	**$ 24,931**	$ 177,770	$ (1,403)
Cash and cash equivalents at beginning of year	**179,413**	1,643	3,046
Cash and cash equivalents at end of year	**$ 204,344**	$ 179,413	$ 1,643
Supplementary Information:			
Interest paid less amounts capitalized	**$ 11,849**	$ 43,419	$ 46,033
Federal and state income taxes paid	**$ 55,134**	$ 282,076	$ 109,109
Dividends received from investments at equity	**$ 5,243**	$ 6,571	$ 3,267

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

New England Power Company
Notes to Financial Statements

Note A - Significant Accounting Policies

1. Nature of Operations:

New England Power Company (the Company), a wholly owned subsidiary of National Grid USA (formerly New England Electric System (NEES)), is a Massachusetts corporation qualified to do business in Massachusetts, New Hampshire, Rhode Island, Connecticut, Maine, and Vermont. The Company is subject, for certain purposes, to the jurisdiction of the regulatory commissions of these six states, the Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935 (1935 Act), the Federal Energy Regulatory Commission (FERC), and the Nuclear Regulatory Commission (NRC). The Company's business is primarily the transmission of electric energy in wholesale quantities to other electric utilities, principally its distribution affiliates Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company, and The Narragansett Electric Company (Narragansett Electric). In addition, the Company also owns minority interests in two joint owned nuclear generating units as well as minority equity interests in four nuclear generating companies (Yankees), three of which own generating facilities that are permanently shut down. The output from these generating facilities is sold to third parties.

2. System of Accounts:

The accounts of the Company are maintained in accordance with the Uniform System of Accounts prescribed by regulatory bodies having jurisdiction.

In preparing the financial statements, management is required to make estimates that affect the reported amounts of assets and liabilities and disclosures of asset recovery and contingent liabilities as of the date of the balance sheets, and revenues and expenses for the period. These estimates may differ from actual amounts if future circumstances cause a change in the assumptions used to calculate these estimates. In addition, certain presentation adjustments have been made to conform prior years with the 1999 presentation.

3. Allowance for Funds Used During Construction (AFDC):

The Company capitalizes AFDC as part of construction costs. AFDC represents the composite interest and equity costs of capital funds used to finance that portion of construction costs not yet eligible for inclusion in rate base. AFDC is capitalized in "Utility plant" with offsetting noncash credits to "Other income" and "Interest." This method is in accordance with an established rate-making practice under which a utility is permitted a return on, and the recovery of, prudently incurred capital costs through their ultimate inclusion in rate base and in the provision for depreciation. The composite AFDC rates were 7.6 percent, 6.1 percent, and 5.9 percent in 1999, 1998, and 1997, respectively.

4. Depreciation and Amortization:

The depreciation and amortization expense included in the statements of income is composed of the following:

Year ended December 31 (In thousands)	**1999**	1998	1997
Depreciation - transmission related	**$ 13,222**	$ 12,553	$ 11,828
Depreciation - all other	**1,286**	46,256	68,432
Nuclear decommissioning costs (Note D-2)	**3,637**	2,719	2,638
Amortization:			
Seabrook 2 property losses	**-**	-	113
Millstone 3 additional amortization, pursuant to 1995 rate settlement	**-**	22,040	15,013
Regulatory assets covered by contract termination charges (Note C)	**84,935**	16,356	-
Total depreciation and amortization expense	**$103,080**	$ 99,924	$ 98,024

Depreciation is provided annually on a straight-line basis. The provision for depreciation as a percentage of weighted average depreciable transmission property was 2.3 percent in 1999, 1998, and 1997. Amortization of Seabrook and Millstone 3 investments above normal depreciation accruals and amortization of regulatory assets covered by contract termination charges (CTC) was in accordance with rate settlement agreements.

5. Cash:

The Company classifies short-term investments with a maturity of 90 days or less as cash.

Note B - Merger Agreements with National Grid and EUA

Merger Agreement with National Grid

On March 22, 2000, the merger of NEES and The National Grid Group plc (National Grid) was completed, with NEES (renamed National Grid USA) becoming a wholly owned subsidiary of National Grid. The Company will maintain its existing name and will remain a wholly owned subsidiary of National Grid USA. The merger is being accounted for by the purchase method, the application of which, including the recognition of goodwill, is being pushed down and reflected on the books of the National Grid USA subsidiaries, including the Company.

Merger Agreement with EUA

In February 1999, NEES, Eastern Utilities Associates (EUA), and Research Drive LLC (Research Drive), a wholly owned subsidiary of NEES, entered into an Agreement and Plan of Merger (EUA Agreement). Pursuant to the EUA Agreement, Research Drive will merge with and into EUA, with EUA becoming a wholly owned subsidiary of National Grid USA.

The acquisition of EUA has received approval or support from EUA shareholders, the Federal Trade Commission (FTC), the FERC, the NRC, the Connecticut Department of Public Utility Control, the Rhode Island Public Utilities Commission, the Massachusetts Department of Telecommunications and Energy, and the Vermont Public Service Board (VPSB). An application has also been filed for approval with the SEC, under the 1935 Act. The acquisition of EUA, including the consolidation of Montaup Electric Company, a wholly owned subsidiary of EUA, into the Company, is expected to be completed following the receipt of an SEC order approving the acquisition, which could come at any time. If the SEC order is not received in time to close the transaction by April 28, 2000, the approval by the FTC, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, expires and will have to be renewed prior to completion of the acquisition.

Note C - Industry Restructuring

Pursuant to legislation enacted in Massachusetts, Rhode Island, and New Hampshire, and settlement agreements approved by state and federal regulators (the Settlement Agreements), customers were granted choice of power supplier in 1998. To facilitate the implementation of customer choice, the Settlement Agreements provided for the termination of the Company's all-requirements contracts with its affiliated distribution companies. The Company's all-requirements contracts with unaffiliated customers were also generally terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service at fixed rates to new customer load in Rhode Island. In addition, as a result of the Settlement Agreements, the Company and its affiliate, Narragansett Electric, sold substantially all of their nonnuclear generating business (divestiture) in September 1998. As part of the divestiture plan, New England Energy Incorporated sold its oil and gas properties in 1998, resulting in a loss of approximately $120 million, before tax, which was reimbursed by the Company. The Company also agreed to endeavor to sell its minority interest in three nuclear power plants and a 60 megawatt interest in a fossil-fueled generating station in Maine.

In conjunction with the divestiture, the Company transferred to the buyer of its nonnuclear generating business (the buyer) its entitlement to power procured under several long-term contracts in exchange for monthly fixed payments by the Company averaging $9.5 million per month through January 2008 (having a net present value at December 31, 1999 of approximately $704 million) toward the above-market cost of those contracts. For certain contracts which have been formally assigned to the buyer, the Company has made lump sum payments equivalent to the present value of the monthly fixed payment obligations of those contracts (approximately $345 million), which were separate from the $704 million figure referred to above.

Under the Settlement Agreements, the Company is permitted to recover costs associated with its former generating investments and related contractual commitments that were not recovered through the sale of those investments ("stranded costs"). These costs are recovered from the Company's wholesale customers through CTCs which the affiliated wholesale customers recover through delivery charges to distribution customers. The recovery of the Company's stranded costs is divided into several categories. Unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets will be fully recovered through the CTC by the end of 2000 and earn a return on equity averaging 9.7 percent. The Company's obligation related to the above-market cost of purchased power contracts and nuclear decommissioning costs are recovered through the CTC as such costs are actually incurred. As the CTC rate declines, the Company, under certain of the Settlement Agreements, earns incentives based on successful mitigation of its stranded costs. These incentives supplement the Company's return on equity. Until such time as the Company divests its operating nuclear interests, the Company will share with customers, through the CTC, 80 percent of the revenues and operating costs related to the units, with shareholders retaining the balance. For further information on the potential sale of the Vermont Yankee and Millstone 3 nuclear generating units, refer to the "Nuclear Units" section below.

Accounting Implications

Because electric utility rates have historically been based on a utility's costs, electric utilities are subject to certain accounting standards that are not applicable to other business enterprises in general. The Company applies the provisions of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71), which requires regulated entities, in appropriate circumstances, to establish regulatory assets, and thereby defer the income statement impact of certain charges or revenues because they are expected to be collected or refunded through future customer billings. In 1997, the Emerging

Issues Task Force of the Financial Accounting Standards Board concluded that a utility that had received approval to recover stranded costs through regulated rates would be permitted to continue to apply FAS 71 to the recovery of stranded costs.

As discussed above, the Company received authorization from the FERC to recover through CTCs substantially all of the costs associated with its former generating business not recovered through the divestiture. Additionally, FERC Order No. 888 enables transmission companies to recover their specific costs of providing transmission service. Therefore, substantially all of the Company's business, including the recovery of its stranded costs, remains under cost-based rate regulation. Because of the nuclear cost-sharing provisions related to the Company's CTC, the Company ceased applying FAS 71 in 1997 to 20 percent of its ongoing nuclear operations, the impact of which is immaterial.

As a result of applying FAS 71, the Company has recorded a regulatory asset for the costs that are recoverable from customers through the CTC. At December 31, 1999, this amounted to approximately $1.3 billion, including $1.0 billion related to the above-market costs of purchased power contracts, $0.3 billion related to accrued Yankee nuclear plant costs, and a smaller amount of other net CTC-related regulatory assets.

In 1998, the Company concluded that its interests in the Millstone 3 and Seabrook 1 nuclear generating units had little, if any, market value, based, in part, on the fact that proposed sales of nuclear units by other utilities have required the seller to set aside amounts for decommissioning in excess of the proceeds from the sale of the units. As a result, the Company recorded an impairment write-down in its reserve for depreciation of approximately $390 million, representing the book value of Millstone 3 and Seabrook 1 at December 31, 1995, less applicable depreciation subsequent to that date.

Note D - Commitments and Contingencies

1. Yankee Nuclear Power Companies

The Company has minority interests in four Yankee Nuclear Power Companies. These ownership interests are accounted for on the equity method. The Company's share of the expenses of the Yankees is accounted for in "Purchased electric energy" on the income statement. A summary of combined results of operations, assets, and liabilities of the four Yankees is as follows:

(In thousands)	**1999**	1998	1997
Operating revenue	**$ 377,039**	$ 439,046	$ 660,742
Net income	**$ 13,890**	$ 23,218	$ 29,959
Company's equity in net income	**$ 2,939**	$ 5,284	$ 5,189
Net plant	**172,100**	171,582	204,689
Other assets	**2,631,750**	2,810,613	3,100,589
Liabilities and debt	**(2,554,261)**	(2,723,454)	(3,036,845)
Net assets	**$ 249,589**	$ 258,741	$ 268,433
Company's equity in net assets	**$ 46,233**	$ 48,538	$ 49,825
Company's purchased electric energy:			
Vermont Yankee	**$ 37,551**	$ 35,108	$ 31,240
All other Yankees	**$ 37,765**	$ 48,543	$ 75,900

At December 31, 1999, $12 million of undistributed earnings of the nuclear power companies were included in the Company's retained earnings.

2. Nuclear Units

Nuclear Units Permanently Shut Down

Three regional nuclear generating companies in which the Company has a minority interest own nuclear generating units that have been permanently shut down. These three units are as follows:

Unit	The Company's Investment %	The Company's Investment $ (millions)	Date Retired	Future Estimated Billings to the Company $ (millions)
Yankee Atomic	30	5	Feb 1992	7
Connecticut Yankee	15	16	Dec 1996	63
Maine Yankee	20	15	Aug 1997	128

In the case of each of these units, the Company has recorded a liability and an offsetting regulatory asset reflecting the estimated future billings from the companies. In a 1993 decision, the FERC allowed Yankee Atomic to recover its undepreciated investment in the plant, including a return on that investment, as well as unfunded nuclear decommissioning costs and other costs. Maine Yankee recovers its costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999. Connecticut Yankee filed a similar request with the FERC, to which several parties intervened in opposition. In August 1998, a FERC Administrative Law Judge (ALJ) issued an initial decision which would allow for full recovery of Connecticut Yankee's unrecovered investment, but precluded a return on that investment. Connecticut Yankee, the Company, and other parties filed with the FERC exceptions to the ALJ's decision. Should the FERC uphold the ALJ's initial decision in its current form, the Company's share of the loss of the return component would total approximately $12 million to $15 million before taxes for the entire recovery period.

A Maine statute provides that if both Maine Yankee and its decommissioning trust fund have insufficient assets to pay for the plant decommissioning, the owners of Maine Yankee are jointly and severally liable for the shortfall.

Under the provisions of the Settlement Agreements, the Company recovers all costs, including shutdown costs, that the FERC allows these Yankee companies to bill to the Company.

Operating Nuclear Units

The Company has minority interests in three operating nuclear generating units which the Company is engaged in efforts to divest: Vermont Yankee, Millstone 3, and Seabrook 1. Uncertainties regarding the future of nuclear generating stations, particularly older units, such as Vermont Yankee, have increased in recent years and could adversely affect their service lives, availability, and costs. These uncertainties stem from a combination of factors, including the acceleration of competitive pressures in the power generation industry and increased NRC scrutiny. The Company performs periodic economic viability reviews of operating nuclear units in which it holds ownership interests.

Vermont Yankee

The following table summarizes the Company's interests in the Vermont Yankee Nuclear Power Corporation:

	(millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
20	11	34	86	42	2012

In November 1999, the Vermont Yankee Nuclear Power Corporation entered into an agreement with AmerGen Energy Company (AmerGen), a joint venture between PECO Energy and British Energy, to sell the assets of Vermont Yankee. Under the terms of the agreement, after a Vermont Yankee contribution toward the plant's decommissioning trust fund, AmerGen will take over the fund and assume responsibility for the actual cost of decommissioning the plant. The agreement also requires the existing power purchasers (including the Company) to continue to purchase the output of the plant or to buy out of the purchased power obligation. In November 1999, the Company signed an agreement to buy out of its obligation, requiring future payments which will be recovered through the Company's CTC. The Company has recorded an accrued liability and offsetting regulatory asset of $80 million for its share of future liabilities related to Vermont Yankee, including the purchased power contract termination payment obligation, but excluding interest and a return allowance. The proposed sale is contingent upon regulatory approvals by the NRC, the SEC, under the 1935 Act, and the VPSB, among others.

Millstone 3

In July 1998, Millstone 3, which is operated by a subsidiary of Northeast Utilities (NU), returned to full operation after being shut down for more than two years.

In August 1997, the Company sued NU in Massachusetts Superior Court for damages resulting from the tortious conduct of NU that caused the shutdown of Millstone 3. The Company's claim for damages included the costs of replacement power during the outage, costs necessary to return Millstone 3 to safe operation, and other additional costs. Most of the Company's incremental replacement power costs have been recovered from customers, either through fuel adjustment clauses or through provisions in the Settlement Agreements.

In August 1997, the Company also sent a demand for arbitration to Connecticut Light & Power Company and Western Massachusetts Electric Company, both subsidiaries of NU (subsidiaries), seeking damages resulting from their breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3.

In November 1999, the Company, NU, and the subsidiaries executed an agreement which settled the litigation and arbitration described above. Under the settlement, NU paid the Company approximately $24 million. In addition, NU also agreed to include the Company's Millstone 3 interest when NU sells its Millstone 3 interest at auction. Amounts received pursuant to a sale will, after reimbursement of the Company's transaction costs and net investment in Millstone 3, be credited to customers.

Nuclear Decommissioning

The Company is liable for its share of decommissioning costs for Millstone 3, Seabrook 1, and all of the Yankees. Decommissioning costs include not only estimated costs to decontaminate the units as required by the NRC, but also costs to dismantle the uncontaminated portion of the units. The Company records decommissioning costs on its books consistent with its rate recovery. The Company is recovering its share of projected decommissioning costs for Millstone 3 and Seabrook 1 through depreciation expense. In addition, the Company is paying its portion of projected decommissioning costs for all of the Yankees through purchased power expense. Such costs reflect estimates of total decommissioning costs approved by the FERC.

In New Hampshire, legislation was enacted in 1998 which makes owners of Seabrook 1, in which the Company owns a 10 percent interest, proportional guarantors for decommissioning costs in the event that an owner without a franchise service territory fails to fund its share of decommissioning costs. Currently, a single owner of an approximate 12 percent share of Seabrook 1 has no franchise service territory. The impact of this legislation to the Company is not considered material to its financial position or results of operation.

The Nuclear Waste Policy Act of 1982 establishes that the federal government (through the Department of Energy (DOE)) is responsible for the disposal of spent nuclear fuel. The federal government requires the Company to pay a fee based on its share of the net generation from the Millstone 3 and Seabrook 1 nuclear generating units. Prior to 1998, the Company recovered this fee through its fuel clause. Under the Settlement Agreements, substantially all of these costs are recovered through CTCs. Similar costs are billed to the Company by Vermont Yankee and are also recovered from customers through CTCs. In 1997, ruling on a lawsuit brought against the DOE by numerous utilities and state regulatory commissions, the U.S. Court of Appeals for the District of Columbia held that the DOE was obligated to begin disposing of utilities' spent nuclear fuel by January 1998. The DOE failed to meet this deadline and is not expected to have a temporary or permanent repository for spent nuclear fuel before 2010, at the earliest. Many utilities, including Yankee Atomic, Connecticut Yankee, and Maine Yankee, are plaintiffs in on-going litigation related to the DOE's failure to accept spent nuclear fuel.

Decommissioning Trust Funds

Each nuclear unit in which the Company has an ownership interest has established a decommissioning trust fund or escrow fund into which payments are being made to meet the projected costs of decommissioning. The table below lists information on the two operating nuclear plants in which the Company is a joint owner.

Unit	The Company's Ownership Interest (%)	The Company's share of (millions of dollars): Net Plant Assets	Estimated Decommissioning Cost (in 1999 $)	Decommissioning Fund Balances*	License Expiration
Millstone 3	12	12**	76	23	2025
Seabrook 1	10	14**	56	13	2026

* Certain additional amounts are anticipated to be available through tax deductions.
** Represents post-December 1995 spending including nuclear fuel. For further information, refer to Note C.

There is no assurance that decommissioning costs actually incurred by Millstone 3, Seabrook 1, or Vermont Yankee, as previously mentioned, will not substantially exceed the estimated amounts. For example, decommissioning cost estimates assume the availability of permanent repositories for both low-level and high-level nuclear waste; those repositories do not currently exist. The temporary low-level repository located in Barnwell, South Carolina may become unavailable, which could increase the cost of decommissioning the Yankee Atomic, Connecticut Yankee, and Maine Yankee plants. If any of the operating units were shut down prior to the end of their operating licenses, which the Company believes is likely, the funds collected for decommissioning to that point would be insufficient. Under the Settlement Agreements, the Company will recover decommissioning costs through CTCs.

Nuclear Insurance

The Price-Anderson Act limits the amount of liability claims that would have to be paid in the event of a single incident at a nuclear plant to $9.5 billion (based upon 106 licensed reactors). The maximum amount of commercially available insurance coverage to pay such claims is $200 million. The remaining $9.3 billion would be provided by an assessment of up to $88.1 million per incident levied on each of the participating nuclear units in the United States, subject to a maximum assessment of $10 million per incident per nuclear unit in any year. The maximum assessment, which was most recently adjusted in 1998, is adjusted for inflation at least every five years. The Company's current interest in Vermont Yankee, Millstone 3, and Seabrook 1 would subject the Company to a $35.4 million maximum assessment per incident. The Company's payment of any such assessment would be limited to a maximum of $4.0 million per year. As a result of the permanent cessation of power operation of the Yankee Atomic, Connecticut Yankee, and Maine Yankee plants, these units have received from the NRC an exemption from participating in the secondary financial protection system under the Price-Anderson Act. However, these plants must continue to maintain $100 million of commercially available nuclear liability insurance coverage.

Each of the nuclear units in which the Company has either an ownership or purchased power interest also carries nuclear property insurance to cover the costs of property damage, decontamination, and premature decommissioning resulting from a nuclear incident. These policies may require additional premium assessments if losses relating to nuclear incidents at units covered by this insurance occur in a prior six-year period. The Company's maximum potential exposure for these assessments, either directly or indirectly, is approximately $4.6 million with respect to the current policy period.

3. Plant Expenditures

The Company's utility plant expenditures are estimated to be approximately $45 million in 2000. At December 31, 1999, substantial commitments had been made relative to future planned expenditures.

4. Hydro-Quebec Interconnection

Three affiliates of the Company were created to construct and operate transmission facilities to transmit power from Hydro-Quebec to New England. Under support agreements entered into at the time these facilities were constructed, the Company agreed to guarantee a portion of the project debt. That portion at December 31, 1999 amounted to $21 million.

5. Hazardous Waste

The Federal Comprehensive Environmental Response, Compensation and Liability Act, more commonly known as the "Superfund" law, imposes strict, joint and several liability, regardless of fault, for remediation of property contaminated with hazardous substances. A number of states, including Massachusetts, have enacted similar laws.

The electric utility industry typically utilizes and/or generates in its operations a range of potentially hazardous products and by-products. The Company currently has in place an internal environmental audit program and an external waste disposal vendor audit and qualification program intended to enhance compliance with existing federal, state, and local requirements regarding the handling of potentially hazardous products and by-products.

The Company has been named as a potentially responsible party (PRP) by either the United States Environmental Protection Agency or the Massachusetts Department of Environmental Protection for several sites at which hazardous waste is alleged to have been disposed. Private parties have also contacted or initiated legal proceedings against the Company regarding hazardous waste cleanup. The Company is currently aware of other possible hazardous waste sites, and may in the future become aware of additional sites, that it may be held responsible for remediating.

Predicting the potential costs to investigate and remediate hazardous waste sites continues to be difficult. There are also significant uncertainties as to the portion, if any, of the investigation and remediation costs of any particular hazardous waste site that may ultimately be borne by the Company. The Company has recovered amounts from certain insurers, and, where appropriate, intends to seek recovery from other insurers and from other PRPs, but it is uncertain whether, and to what extent, such efforts will be successful. The Company believes that hazardous waste liabilities for all sites of which it is aware are not material to its financial position.

6. Town of Norwood Dispute

From 1983 until 1998, the Company was the wholesale power supplier for the Town of Norwood, Massachusetts (Norwood). In April 1998, Norwood began taking power from another supplier. Pursuant to a tariff amendment approved by the FERC in May 1998, the Company has been assessing Norwood a CTC. Through December 1999, the charges assessed Norwood amount to approximately $15 million, all of which remain unpaid. The Company is pursuing a collection action in Massachusetts Superior Court.

Separately, Norwood filed suit in Federal District Court (District Court) in April 1997 alleging that the divestiture violated the terms of the 1983 power contract and contravened antitrust laws. The District Court dismissed the lawsuit. On appeal, the First Circuit Court of Appeals (First Circuit) also consolidated appeals Norwood made from FERC's orders approving the divestiture, the wholesale rate settlement between the Company and its distribution affiliates, and the CTC tariff amendment. On February 2, 2000, the First Circuit dismissed Norwood's appeal from the FERC orders and dismissed its appeal from all but one of Norwood's District Court claims, which relates to the creation of generation market power. On February 28, 2000 and March 3, 2000, respectively, the First Circuit denied Norwood's petition for further review of its District Court claims decision and its decision on the FERC orders.

Norwood has also appealed a 1999 FERC decision that rejected Norwood's challenge to the calculation of the CTC based on the term of the 1983 power contract.

Note E - Employee Benefits

1. Pension Plans:

The Company participates with other subsidiaries of National Grid USA in noncontributory, defined-benefit plans covering substantially all employees of the Company. The plans provide pension benefits based on the employee's compensation during the five years prior to retirement. Absent unusual circumstances, the Company's funding policy is to contribute each year the net periodic pension cost for that year. However, the contribution for any year will not be less than the minimum contribution required by federal law or greater than the maximum tax deductible amount.

Net pension cost for 1999, 1998, and 1997 included the following components:

Year ended December 31 (thousands of dollars)	**1999**	1998	1997
Service cost - benefits earned during the period	**$ 527**	$ 2,430	$ 2,887
Plus (less):			
Interest cost on projected benefit obligation	**7,044**	7,435	7,003
Return on plan assets at expected long-term rate	**(8,090)**	(8,675)	(7,842)
Amortization of transition obligation	**(170)**	(184)	(175)
Amortization of prior service cost	**115**	161	171
Amortization of net (gain)/loss	**36**	159	65
Curtailment (gain)/loss	**-**	(5,680)	-
Benefit cost	**$ (538)**	$ (4,354)	$ 2,109
Special termination benefits not included above	**$ -**	$ 10,911	$ -

The funded status of the plans cannot be presented separately for the Company as the Company participates in the plans with other National Grid USA subsidiaries. The following table sets forth the funded status of the National Grid USA companies' plans at December 31:

(millions of dollars)	**1999**	1998
Benefit obligation	**$ 789**	$ 843
Unrecognized prior service costs	**(5)**	(6)
Transition liability not yet recognized (amortized)	**(2)**	(2)
Additional minimum liability	**6**	7
	788	842
Plan assets at fair value	**947**	837
Transition asset not yet recognized (amortized)	**(5)**	(6)
Net (gain)/loss not yet recognized (amortized)	**(206)**	(92)
	736	739
Accrued (prepaid) pension benefits recorded on books	**$ 52**	$ 103

The following provides a reconciliation of benefit obligations and plan assets:

(millions of dollars)	1999	1998
Changes in benefit obligation:		
Benefit obligation at January 1	**$ 843**	$ 819
Service cost	**11**	14
Interest cost	**56**	55
Actuarial (gain)/loss	**(55)**	(5)
Benefits paid	**(66)**	(94)
Special termination benefits	**-**	64
Curtailment	**-**	(11)
Plan amendments	**-**	1
Benefit obligation at December 31	**$ 789**	$ 843
Reconciliation of change in plan assets:		
Fair value of plan assets at January 1	**$ 837**	$ 834
Actual return on plan assets during year	**117**	93
Company contributions	**59**	4
Benefits paid from plan assets	**(66)**	(94)
Fair value of plan assets at December 31	**$ 947**	$ 837

Year ended December 31	2000	1999	1998	1997
Assumptions used to determine pension cost:				
Discount rate	7.75%	6.75%	6.75%	7.25%
Average rate of increase in future compensation level	5.10%	4.13%	4.13%	4.13%
Expected long-term rate of return on assets	8.50%	8.50%	8.50%	8.50%

The plans' funded status at December 31, 1999 and 1998 were calculated using the assumed rates from 2000 and 1999, respectively, and the 1983 Group Annuity Mortality table.

Plan assets are composed primarily of equity and fixed income securities.

2. Postretirement Benefit Plans Other than Pensions (PBOPs):

The Company provides health care and life insurance coverage to eligible retired employees. Eligibility is based on certain age and length of service requirements and in some cases retirees must contribute to the cost of their coverage.

The Company's total cost of PBOPs for 1999, 1998, and 1997 included the following components:

Year ended December 31 (thousands of dollars)	1999	1998	1997
Service cost - benefits earned during the period	**$ 193**	$ 1,109	$ 1,363
Plus (less):			
Interest cost on projected benefit obligation	**2,816**	3,244	3,545
Return on plan assets at expected long-term rate	**(2,896)**	(2,656)	(2,343)
Amortization of transition obligation	**85**	1,732	2,556
Amortization of prior service cost	**-**	5	8
Amortization of net (gain)/loss	**(1,252)**	(1,138)	(983)
Curtailment (gain)/loss	**-**	27,149	-
Benefit cost	**$ (1,054)**	$29,445	$ 4,146
Special termination benefits not included above	**$ -**	$ 439	$ -

The following table sets forth the Company's benefits earned and the plans' funded status:

At December 31 (millions of dollars)	1999	1998
Benefit obligation	$ 42	$ 41
Unrecognized prior service costs	-	-
Transition liability not yet recognized (amortized)	(1)	(1)
	41	40
Plan assets at fair value	39	36
Net (gain)/loss not yet recognized (amortized)	(25)	(26)
	14	10
Accrued (prepaid) PBOPs recorded on books	$ 27	$ 30

The following provides a reconciliation of benefit obligations and plan assets:

(millions of dollars)	1999	1998
Changes in benefit obligation:		
Benefit obligation at January 1	$ 41	$ 51
Service cost	-	1
Interest cost	3	3
Actuarial (gain)/loss	-	2
Benefits paid	(2)	(2)
Special termination benefits	-	-
Curtailment	-	(14)
Benefit obligation at December 31	$ 42	$ 41
Reconciliation of change in plan assets:		
Fair value of plan assets at January 1	$ 36	$ 34
Actual return on plan assets during year	4	4
Company contributions	1	-
Benefits paid from plan assets	(2)	(2)
Fair value of plan assets at December 31	$ 39	$ 36

Year ended December 31	2000	1999	1998	1997
Assumptions used to determine postretirement benefit cost:				
Discount rate	7.75%	6.75%	6.75%	7.25%
Expected long-term rate of return on assets	8.42%	8.35%	8.27%	8.21%
Health care cost rates:				
1997 to 1999		5.25%	5.25%	8.00%
2000	8.25%	5.25%	5.25%	6.25%
2001	6.75%	5.25%	5.25%	6.25%
2002 to 2004	5.25%	5.25%	5.25%	6.25%
2005 and beyond	5.25%	5.25%	5.25%	5.25%

The plans' funded status at December 31, 1999 and 1998 were calculated using the assumed rates in effect for 2000 and 1999, respectively.

The assumptions used in the health care cost trends have a significant effect on the amounts reported. A one percentage point change in the assumed rates would increase the accumulated postretirement benefit obligation (APBO) as of December 31, 1999 by approximately $5 million or decrease the APBO by approximately $4 million, and change the net periodic cost for 1999 by approximately $350,000.

The Company generally funds the annual tax-deductible contributions. Plan assets are invested in equity and fixed income securities and cash equivalents.

2. Early Retirement and Special Severance Programs:

In 1998, the Company offered a voluntary early retirement program to all employees who were at least 55 years old with 10 years of service. This program was part of an organizational review with the goal of streamlining operations and reducing the work force to reflect industry restructuring. The early retirement offer was accepted by 104 employees. A special severance program was also utilized in 1998 for employees affected by the organizational restructuring, but who were not eligible for, or did not accept, the early retirement offer. The cost of these programs was in part reimbursed by the buyer at the closing of the divestiture and will be recovered in part from customers as a component of stranded cost recovery.

Note F - Income Taxes

The Company and other subsidiaries participate with National Grid USA in filing consolidated federal income tax returns. The Company's income tax provision is calculated on a separate return basis. Federal income tax returns have been examined and reported on by the Internal Revenue Service through 1993.

Total income taxes in the statements of income are as follows:

Year ended December 31 (In thousands)	**1999**	1998	1997
Income taxes charged to operations	**$ 37,633**	$ 73,594	$ 90,009
Income taxes charged (credited) to "Other income"	**1,985**	(19,582)	(373)
Total income taxes	**$ 39,618**	$ 54,012	$ 89,636

Total income taxes, as shown above, consist of the following components:

Year ended December 31 (In thousands)	**1999**	1998	1997
Current income taxes	**$ 25,507**	$ 280,734	$102,364
Deferred income taxes	**25,921**	(204,129)	(10,705)
Investment tax credits, net	**(11,810)**	(22,593)	(2,023)
Total income taxes	**$ 39,618**	$ 54,012	$ 89,636

Investment tax credits (ITC) have been deferred and amortized over the estimated lives of the property giving rise to the credits. ITC amortization in 1999 reflects the accelerated amortization of the property giving rise to the credits, while the increase in amortization of ITC in 1998 compared with 1997 results from the recognition in income of unamortized ITC related to the generating assets divested during 1998.

Total income taxes, as shown above, consist of federal and state components as follows:

Year ended December 31 (In thousands)	1999	1998	1997
Federal income taxes	**$ 33,746**	$ 41,255	$ 73,077
State income taxes	**5,872**	12,757	16,559
Total income taxes	**$ 39,618**	$ 54,012	$ 89,636

With regulatory approval from the FERC, the Company has adopted comprehensive interperiod tax allocation (normalization) for temporary book/tax differences.

Total income taxes differ from the amounts computed by applying the federal statutory tax rates to income before taxes. The reasons for the differences are as follows:

Year ended December 31 (In thousands)	1999	1998	1997
Computed tax at statutory rate	**$ 38,721**	$ 61,917	$ 81,963
Increases (reductions) in tax resulting from:			
Amortization of investment tax credits	**(7,677)**	(15,157)	(2,023)
State income taxes, net of federal income tax benefit	**3,817**	8,292	10,763
Rate recovery of deficiency in deferred tax reserves	**8,207**	-	-
Prior year tax adjustment	**(2,028)**	(188)	(313)
All other differences	**(1,422)**	(852)	(754)
Total income taxes	**$ 39,618**	$ 54,012	$ 89,636

The following table identifies the major components of total deferred income taxes:

At December 31 (In millions)	1999	1998
Deferred tax asset:		
Plant related	**$ 67**	$ 76
Investment tax credits	**8**	13
All other	**2**	24
	77	113
Deferred tax liability:		
Plant related	**(157)**	(53)
All other, principally regulatory assets	**(100)**	(225)
	(257)	(278)
Net deferred tax liability	**$ (180)**	$ (165)

Note G - Short-term Borrowings and Other Accrued Expenses

At December 31, 1999, the Company had $39 million of short-term debt outstanding. The Company has regulatory approval from the SEC, under the 1935 Act, to issue up to $375 million of short-term debt. The Company plans to seek the necessary regulatory approvals in 2000 which would allow the $39 million of variable rate debt to remain outstanding through 2015. This would result in classifying the debt as long-term rather than short-term. National Grid USA and certain subsidiaries, including the Company, with regulatory approval, operate a money pool to more effectively utilize cash resources and to reduce outside short-term borrowings. Short-term borrowing needs are met first by available funds of the money pool participants. Borrowing companies pay interest at a rate designed to approximate the cost of outside short-term borrowings. Companies which invest in the pool share the interest earned on a basis proportionate to their average monthly investment in the money pool. Funds may be withdrawn from or repaid to the pool at any time without prior notice.

At December 31, 1999, the Company had lines of credit and standby bond purchase facilities with banks totaling $460 million which are available to provide liquidity support for $410 million of the Company's short-term and long-term bonds in tax-exempt commercial paper mode (including the $39 million discussed above) and for other corporate purposes. There were no borrowings under these lines of credit at December 31, 1999. Fees are paid on the lines and facilities in lieu of compensating balances.

The components of other accrued expenses are as follows:

At December 31 (In thousands)	**1999**	1998
Accrued wages and benefits	**$ 1,063**	$ 3,059
Rate adjustment mechanisms	**14,550**	16,781
Other	**80**	246
	$15,693	$20,086

Note H - Cumulative Preferred Stock

A summary of cumulative preferred stock at December 31, 1999 and 1998 is as follows (in thousands of dollars except for share data):

	Shares Outstanding		Amount		Dividends Declared		Call Price
	1999	1998	**1999**	1998	**1999**	1998	
$100 par value							
6.00% Series	**15,672**	15,672	**$ 1,567**	$1,567	**$ 94**	$ 277	(a)
4.56% Series	-	-	-	-	-	247	
4.60% Series	-	-	-	-	-	236	
4.64% Series	-	-	-	-	-	98	
6.08% Series	-	-	-	-	-	372	
Total	**15,672**	15,672	**$ 1,567**	$1,567	**$ 94**	$ 1,230	

(a) Noncallable.

The annual dividend requirement for cumulative preferred stock was $94,000 at the end of 1999 and 1998. In 1998, the Company repurchased or redeemed preferred stock with an aggregate par value of $38 million.

There are no mandatory redemption provisions on the Company's cumulative preferred stock.

Note I - Long-term Debt

A summary of long-term debt is as follows:

At December 31 (In thousands)				
Series	Rate %	Maturity	**1999**	1998
Pollution Control Revenue Bonds:				
MIFA 1 (a)	variable	March 1, 2018	**$ 79,250**	$ 79,250
BFA 1 (b)	variable	November 1, 2020	**135,850**	135,850
BFA 2 (b)	variable	November 1, 2020	**50,600**	50,600
MIFA 2 (a)	variable	October 1, 2022	**106,150**	106,150
Unamortized discounts			**(79)**	(85)
Total long-term debt			**$ 371,771**	$ 371,765

(a) MIFA = Massachusetts Industrial Finance Authority
(b) BFA = Business Finance Authority of the State of New Hampshire

At December 31, 1999, interest rates on the Company's variable rate long-term bonds ranged from 3.55 percent to 3.90 percent.

At December 31, 1999, the Company's long-term debt had a carrying value and fair value of approximately $372,000,000. The fair value of debt that reprices frequently at market rates approximates carrying value.

Note J - Common Stock

The Company repurchased shares of its common stock in 1999 and 1998 as follows (dollar amounts expressed in thousands):

			Reductions to :		
Year	Number of Shares	Cash Paid	Common stock and related premium	Other paid-in capital	Retained earnings
1999	130,000	$ 18,056	$ 4,348	$ 6,623	$ 7,085
1998	2,700,000	$417,960	$90,266	$133,876	$193,818

Note K - Supplementary Income Statement Information

Advertising expenses, expenditures for research and development, and rents were not material and there were no royalties paid in 1999, 1998, or 1997. Taxes, other than income taxes, charged to operating expenses are set forth by classes as follows:

Year ended December 31 (In thousands)	**1999**	1998	1997
Municipal property taxes	**$17,640**	$ 42,080	$ 59,102
Federal and state payroll and other taxes	**2,642**	6,412	8,209
	$20,282	$ 48,492	$ 67,311

New England Power Service Company, an affiliated service company operating pursuant to the provisions of Section 13 of the 1935 Act, furnished services to the Company at the cost of such services. These costs amounted to $43,584,000, $74,203,000, and $91,985,000, including capitalized construction costs of $17,229,000, $21,281,000, and $24,347,000, in 1999, 1998, and 1997, respectively.

Selected Financial Information

Year ended December 31 (In millions)	**1999**	1998	1997	1996	1995
Operating revenue	**$ 596**	$1,218	$1,678	$1,600	$1,571
Net income	**$ 71**	$ 123	$ 145	$ 152	$ 151
Total assets	**$ 2,303**	$2,415	$2,763	$2,648	$2,648
Capitalization:					
Common equity	**$ 332**	$ 521	$ 913	$ 906	$ 889
Cumulative preferred stock	**2**	1	40	40	61
Long-term debt	**372**	372	648	733	735
Total capitalization	**$ 706**	$ 894	$1,601	$1,679	$1,685
Preferred dividends declared	**$ -**	$ 1	$ 2	$ 3	$ 3
Common dividends declared	**$ 241**	$ 131	$ 135	$ 134	$ 135

Selected Quarterly Financial Information (Unaudited)

(In thousands)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
1999				
Operating revenue	$167,177	$139,620	$142,066	$147,478
Operating income	$ 22,058	$ 13,796	$ 18,782	$ 23,927
Net income	$ 20,345	$ 14,254	$ 17,669	$ 18,746
1998				
Operating revenue	$401,147	$358,320	$321,569	$137,304
Operating income	$ 48,740	$ 32,523	$ 54,647	$ 21,452
Net income	$ 35,950	$ 20,425	$ 47,956	$ 18,564

Per share data is not relevant because the Company's common stock is wholly owned by National Grid USA, a wholly owned subsidiary of The National Grid Group plc.

Grant Thornton

GRANT THORNTON LLP

Accountants and
Management Consultants

The U.S. Member Firm of
Grant Thornton International

FINANCIAL STATEMENTS AND
REPORT OF INDEPENDENT
CERTIFIED PUBLIC ACCOUNTANTS
TAUNTON MUNICIPAL LIGHTING PLANT
December 31, 1999 and 1998

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Management Consultants
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Report of Independent Certified Public Accountants

Municipal Light Commission
of the City of Taunton
Taunton, Massachusetts

We have audited the accompanying balance sheets of the Taunton Municipal Lighting Plant (a department of the City of Taunton) as of December 31, 1999 and 1998, and the related statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Plant's management. Our responsibility is to express an opinion on these financial statements based on our audits.

Except as discussed in the following paragraph, 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 our audits provide a reasonable basis for our opinion.

As discussed in Note H to the financial statements, certain disclosures required by the Governmental Accounting Standards Board relating to pensions have been omitted.

In our opinion, except for the omission of certain pension plan disclosures required by the Governmental Accounting Standards Board, the financial statements referred to above present fairly, in all material respects, the financial position of the Taunton Municipal Lighting Plant as of December 31, 1999 and 1998, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Boston, Massachusetts
February 29, 2000

Grant Thornton LLP

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Taunton Municipal Lighting Plant

BALANCE SHEETS

December 31,

ASSETS

	1999	1998
UTILITY PLANT - AT COST		
Plant in service	$120,391,621	$114,082,267
Less accumulated depreciation	77,518,481	72,905,729
Net utility plant in service	42,873,140	41,176,538
Investment in Seabrook	2,547,252	2,681,176
Construction work in progress	4,921,427	6,069,668
Total utility plant	50,341,819	49,927,382
DEPRECIATION FUND (including certificates of deposit of $4,000,000 and $4,000,000 in 1999 and 1998, respectively)	10,707,094	11,140,017
SICK LEAVE TRUST FUND	4,695,784	4,496,039
OTHER ASSETS		
Investment in Hydro Quebec Project	287,512	287,512
Investment in Energy New England LLC	102,125	365,462
Due from Plant Retirement Trust	647,137	619,787
Other	8,276	64,320
CURRENT ASSETS		
Cash	1,519,505	673,277
Cash - rate stabilization fund	442,064	-
Customer deposits	566,083	568,142
Accounts receivable, less allowance for doubtful accounts of $1,364,053 and $1,099,131 respectively	4,499,245	4,762,665
Materials and supplies inventory	2,153,156	1,453,022
Prepaid expenses	1,968,192	1,605,786
Total current assets	11,148,245	9,062,892
	$ 77,937,992	$ 75,963,411

RETAINED EARNINGS AND LIABILITIES

	1999	1998
RETAINED EARNINGS		
Appropriated retained earnings		
Loans repayment	$ 21,787,000	$ 20,637,000
Construction repayment	32,434	32,434
	21,819,434	20,669,434
Unappropriated retained earnings	33,658,565	31,955,286
Total retained earnings	55,477,999	52,624,720
LONG-TERM DEBT	10,100,094	11,353,447
DEFERRED REVENUE - RATE STABILIZATION	442,064	-
CURRENT LIABILITIES		
Accounts payable	3,385,267	3,621,676
Customer deposits	382,409	418,072
Current maturities of long-term debt	1,250,000	1,150,000
Accrued liabilities		
Sick leave	4,695,787	4,281,682
Vacation	930,782	749,368
Interest	434,137	429,874
Power	678,124	1,080,712
Payroll	86,245	157,523
Other	75,084	96,337
Total current liabilities	11,917,835	11,985,244
	$ 77,937,992	$ 75,963,411

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF EARNINGS

Years ended December 31,

	1999	1998
Operating revenues		
Sales of electricity		
Commercial and industrial	$26,218,953	$24,730,067
Residential	17,256,181	16,417,694
Sales for resale	3,449,716	3,410,475
Municipal	2,290,913	2,151,474
	49,215,763	46,709,710
Other operating revenues	259,450	257,381
Total operating revenues	49,475,213	46,967,091
Operating expenses		
Power production	27,552,837	25,404,636
Transmission and distribution	4,811,408	5,347,013
Customer accounting	2,178,445	1,609,128
Administrative and general	3,562,884	5,052,877
Depreciation and amortization	4,842,289	4,673,659
Nuclear expense	269,655	202,574
Total operating expenses	43,217,518	42,289,887
Earnings from operations	6,257,695	4,677,204
Other expense (income)		
Internet expense - net	130,711	238,733
Interest expense	933,952	1,025,551
Interest income	(213,351)	(556,348)
Unrealized gains on investments	-	(4,418)
Other expense (income)	193,104	67,519
Total other expense	1,044,416	771,037
Earnings before provision for payment in lieu of taxes	5,213,279	3,906,167
Provision for payment in lieu of taxes	2,360,000	2,360,000
NET EARNINGS	$ 2,853,279	$ 1,546,167

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF RETAINED EARNINGS

Years ended December 31, 1999 and 1998

	Appropriated Retained Earnings		Unappropriated Retained Earnings
	Loan Repayment	Construction Repayment	
Balance at December 31, 1997	$19,572,000	$32,434	$31,474,119
Transfer for bond repayment	1,065,000	-	(1,065,000)
Net earnings	-	-	1,546,167
Balance at December 31, 1998	20,637,000	32,434	31,955,286
Transfer for bond repayment	1,150,000	-	(1,150,000)
Net earnings	-	-	2,853,279
Balance at December 31, 1999	$21,787,000	$32,434	$33,658,565

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

STATEMENTS OF CASH FLOWS

Years ended December 31,

	1999	1998
Increase (Decrease) in Cash and Cash Equivalents		
Cash flows from operating activities:		
Net earnings	$ 2,853,279	$ 1,546,167
Adjustments to reconcile net earnings to net cash and cash equivalents provided by operating activities:		
Depreciation and amortization	4,842,289	4,673,659
Amortization of bond premium	(3,353)	(3,354)
Equity in (income) losses of Seabrook investment	133,924	(19,559)
Equity in losses of Energy New England LLC investment	263,337	134,538
Change in assets and liabilities:		
(Increase) decrease in customer deposit funds	2,059	(102,250)
(Increase) decrease in accounts receivable	263,420	(759,550)
(Increase) in due from Plant Retirement Trust	(27,350)	(69,079)
(Increase) decrease in inventory	(700,134)	163,218
(Increase) in prepaid expenses	(362,406)	(1,427,389)
Decrease in other assets	56,044	61,152
Increase (decrease) in accounts payable	(236,409)	2,436,857
Decrease in deferred fuel or customer credits	-	122,109
Increase in deferred revenue - rate stabilization	442,064	-
Increase (decrease) in customer deposits	(35,663)	53,799
Increase (decrease) in accrued liabilities	104,663	1,073,656
Net cash provided by operating activities	7,595,764	7,883,974
Cash flows from investing activities:		
Net additions to utility plant	(5,390,650)	(7,315,142)
Investment in Energy New England LLC	-	(500,000)
Proceeds from maturing long term certificates of deposits - depreciation fund	-	4,000,000
Increase in Sick Leave Trust Fund	(199,745)	(363,910)
Net cash used in investing activities	(5,590,395)	(4,179,052)
Cash flows from financing activities:		
Payment of long-term debt	(1,150,000)	(1,065,000)
Net increase in cash and cash equivalents	855,369	2,639,922
Cash and cash equivalents at beginning of year	11,813,294	9,173,372
Cash and cash equivalents at end of year	$12,668,663	$11,813,294

Taunton Municipal Lighting Plant

STATEMENTS OF CASH FLOWS - CONTINUED

Years ended December 31,

	1999	1998
Cash and cash equivalents at end of year is reflected on the balance sheets as follows:		
Depreciation fund (exclusive of long-term certificates of deposit)	$10,707,094	$11,140,017
Cash - operating	1,519,505	673,277
Cash - rate stabilization fund	442,064	-
	$12,668,663	$11,813,294

Supplemental Disclosure of Cash Flow Information:

	1999	1998
Cash paid during the year for interest	$ 929,689	$ 1,061,051

The accompanying notes are an integral part of these statements.

Taunton Municipal Lighting Plant

NOTES TO FINANCIAL STATEMENTS

December 31, 1999 and 1998

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A summary of Taunton Municipal Lighting Plant's (the "Plant") significant accounting policies consistently applied in the preparation of the accompanying financial statements follows.

1. Nature of Business

The Plant is a regulated municipal electric utility located in Taunton, Massachusetts. The Plant operates as an enterprise fund of the City of Taunton, Massachusetts, and produces, purchases and distributes electricity to approximately 32,000 customers in the City of Taunton and the surrounding areas. The Plant also operates an internet access business unit. Revenue and expense for this business unit is presented in other expense (income) in the statement of earnings. The business unit leases certain assets from the Plant. For the years ended December 31, 1999 and 1998, other operating revenue for the Plant and internet expense includes approximately $153,000 and $146,000, respectively, relating to this lease.

2. Use of Estimates

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

Estimates relating to the allowance for doubtful accounts and contingencies (see note F) represent the significant estimates included in the financial statements. Management bases their estimates of these items on historical experience, specific identification and future expectations.

3. Rates

The Plant is under the charge and control of the Municipal Light Plant Commissioners in accordance with Chapter 164, Section 55 of the General Laws of the Commonwealth of Massachusetts. Electric power is both produced and purchased and is distributed to customers within their service area. The rates charged by the Plant to its customers are filed with the Department of Telecommunications and Energy ("DTE") (formerly the Massachusetts Department of Public Utilities) and are subject to Chapter 164, Section 58 of the General Laws, which provide that prices shall be fixed to yield not more than 8% per annum on the cost of the plant after repayment of operating expenses, interest on outstanding debt, the requirements of any serial debt and depreciation. The Plant's resulting net earnings amounted to approximately 5.7% and 3.1% of utility plant in 1999 and 1998, respectively.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

4. Depreciation

Pursuant to the DTE regulations, depreciation is calculated as a percentage of depreciable property at January 1. Depreciation is computed using a rate of 4% of the cost of depreciable property.

Depreciation Fund cash is used in accordance with state laws for replacements, enlargements and additions to the utility plant in service.

5. Pension Plan

Substantially all employees of the Plant are covered by a contributory pension plan administered by the City of Taunton in conformity with State Retirement Board requirements (see note G).

6. Inventory

Materials and supplies inventory is carried at cost, principally on the average cost method.

7. Sick Leave Trust Fund

The Plant established a Sick Leave Trust Fund ("Trust") in 1982 for the financing of future sick leave payments. It is the Plant's intention that the Trust be funded to the extent of the Plant's sick leave liability and that future sick leave expense will be paid by the Trust once full funding is achieved. Full funding was achieved in fiscal 1999. The assets of the Trust are shown in the financial statements to provide a more meaningful presentation, as the assets of the Trust are for the sole benefit of the Plant.

In March 1997, the Governmental Accounting Standards Board issued Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools" ("GASB 31"). Under GASB 31, investments are required to be reported at fair value in the balance sheet, and investment income, including changes in fair value of investments, is required to be recognized as revenue in the operating statement. The provisions of GASB 31 were adopted retroactively. The Plant previously accounted for its investments under Statement of Accounting Standards No. 115. The adoption of GASB 31 resulted in an increase in net income of $4,418 for the year ended December 31, 1998.

Realized gains and losses, and declines in value are included in the statement of earnings.

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES - Continued

Net investment income for the Trust of approximately $219,000 and $196,000 in 1999 and 1998, respectively, is reflected in the statements of earnings as an offset to compensated absence expense, as these funds are restricted and can only be used for the payment of sick leave benefits. The net expense for sick leave was approximately $77,000 and $69,000 for the years ended December 31, 1999 and 1998, respectively.

8. Deferred Fuel Costs

The Plant's rates include a Purchased Power Cost Adjustment (PPCA) which allows an adjustment of rates charged to customers in order to recover all changes in power costs from stipulated base costs. The PPCA provides for a quarterly reconciliation of total power costs billed with the actual cost of power incurred.

9. Investment in Seabrook

The Plant's Investment in Seabrook represents a 0.10034% joint ownership share. The Plant records annually depreciation computed at 4% of the initial investment in Seabrook. The Plant's percentage share of new plant additions are capitalized and their share of operating and maintenance expenses, and decommissioning expenses (see note C) are charged against earnings.

10. Cash Equivalents

For purposes of the Statement of Cash Flows, the Plant considers certificates of deposit with maturities of three months or less to be cash equivalents.

11. Internet

The Plant experienced its first full year as an internet provider. This new venture generated revenues of approximately $939,000 and $443,000 for the years ended December 31, 1999 and 1998, respectively. Expenses were approximately $1,070,000 and $682,000 for the same periods.

NOTE B - CASH AND CERTIFICATES OF DEPOSIT

The Plant's cash is deposited with the City of Taunton Treasurer who commingles it with other City funds. The City invests the cash and credits the Plant each year with interest earned on the cash deposits.

Cash and certificates of deposit deposited with the City of Taunton consists of the following at December 31,

	1999	1998
Interest bearing pooled funds including restricted customer deposits of $566,083 and $568,142, respectively	$ 9,234,746	$ 8,381,436
Certificates of deposit with rates of 5.5% and 4.5% maturing February 2000 and February 1999 for fiscal 1999 and 1998, respectively	4,000,000	4,000,000
	$13,234,746	$12,381,436

Cash and certificates of deposit at December 31, is reflected as follows:

	1999	1998
Depreciation Fund - capital additions and replacements	$ 5,003,844	$ 6,098,898
Depreciation Fund - Major overhaul	327,318	27,318
Depreciation Fund - Unit 9 principal and interest	4,647,248	4,285,117
Depreciation Fund - other	728,684	728,684
Cash - including the rate stabilization fund	1,961,569	673,277
Customer deposit principal and interest fund	566,083	568,142
	$13,234,746	$12,381,436

Certain cash amounts have been designated as restricted for the purpose of a rate stabilization fund. This fund is designated to offset potential future customer rate increases.

NOTE C - INVESTMENTS

The Plant is a 0.10034% joint owner of the Seabrook New Hampshire Unit 1.

The joint owners of Seabrook have established a Decommissioning Fund that is currently held by a Trustee. The Plant's share of the estimated decommissioning liability is approximately $491,000 as of January 1, 1998 (the most current valuation date). The Plant is currently contributing, based on a present value formula, $1,534 per month over 28 years.

NOTE C - INVESTMENTS - Continued

Energy New England

In 1998, the Plant, in conjunction with the Reading Municipal Light Department, the Braintree Electric Light Department and the Connecticut Municipal Electric Energy Cooperative, formed a new cooperative, Energy New England LLC, as allowed under Chapter 164 of the General Laws of the Commonwealth of Massachusetts. Each founding system invested $500,000 in order to initially fund the new corporation. Energy New England is an energy and energy services cooperative established to assist publicly owned entities to ensure their continued viability in the newly deregulated wholesale electric utility markets and to strengthen their competitive position in the retail energy market for the benefit of the municipal entities' customers. Energy New England functions as an autonomous, entrepreneurial business unit that is free from many of the constraints imposed on traditional municipal utility operations. Each founding member has one seat on the Board of Directors along with three outside Directors. Energy New England commenced the management of the founders power supply operations in the newly restructured NEPOOL wholesale markets as of May 1, 1999. The Plant records this investment under the equity method. Included in other expense is approximately $102,000 and $135,000 for the years ended December 31, 1999 and 1998, respectively, representing the Plant's share of Energy New England's net losses through December 31, 1999.

NOTE D - LONG-TERM DEBT

Long-term debt is comprised of the following bonds:

	1999	1998
Electric Loan Act of 1969		
Interest rate - 8%, interest payable February 1 and August 1, due serially to February 1, 2006	$11,330,000	$12,480,000
Unamortized premium	20,094	23,447
	11,350,094	12,503,447
Less current maturities	1,250,000	1,150,000
Total long-term debt	$10,100,094	$11,353,447

NOTE D - LONG-TERM DEBT - Continued

Aggregate maturities of long-term debt at December 31, 1999, are as follows:

2000	$ 1,250,000
2001	1,350,000
2002	1,465,000
2003	1,585,000
2004	1,750,000
Thereafter	3,930,000
	$11,330,000

NOTE E - CONTRIBUTION IN LIEU OF TAXES

The Plant contributed $2,360,000 in 1999 and 1998 to the City of Taunton in lieu of taxes. All contributions to the City are voted by the Municipal Light Commission.

NOTE F - COMMITMENTS AND CONTINGENCIES

Interconnection Agreement

The City of Taunton, acting by vote of its Municipal Lighting Plant Commission, entered into an agreement with Montaup Electric Company ("Montaup"), dated July 31, 1970, as amended, concerning interconnection of electrical operations, purchase and sale of kilowatt capacity, and construction by Taunton of a generating unit of approximately 110 megawatt capability. During 1998, the City agreed to exchange with Montaup Electric Company fifteen (15) megawatts of Unit No. 9 capacity for ten (10) megawatts of capacity from the Canal No. 2 generating unit, 50% of which is owned by Montaup. The Plant credited to sales for resale $438,757 of energy charges billed to Montaup Electric Company in 1998 for its share of power under the interconnection agreement. Although the interconnection agreement arrangements remain in place, the exchange of capacity and related energy was terminated effective December 1998.

NOTE F - COMMITMENTS AND CONTINGENCIES - Continued

Hydro-Quebec Agreement

In 1988, the Plant entered into an agreement with the Massachusetts Municipal Wholesale Electric Company and other New England Utilities to support the operation of a transmission line to permit the interchange of electricity between such utilities and Hydro-Quebec Electric Corporation (HydroQuebec). In connection with the agreement, the Plant advanced approximately $800,000 toward development of the project of which approximately $450,000 was returned after the project had obtained financing. In 1991, the Hydro Quebec project was completed. Upon completion of this project, each participant received stock in the New England Hydro Transmission Electric Company and The New England Hydro Transmission Corporation proportional to their advances. The investment is being accounted for on the cost basis. The stock received is not readily marketable, but gives the holder rights to purchase power at a percentage of the fossil fuel rate.

During the years ended December 31, 1999 and 1998, the Plant received dividends from the above noted Companies of approximately $62,000 and $64,000, respectively.

Litigation and Other Matters

1. The Plant purchases power (.5337% of total Maine Yankee Plant output) from Maine Yankee Atomic Power Company ("Maine Yankee") pursuant to a Contract that entitles the Plant to a pro rata share of the Maine Yankee Plant (the "Maine Plant") output. On August 6, 1997, the Maine Yankee Board of Directors officially terminated the Maine Plant. During both 1996 and 1997, the Maine Plant ran only sporadically. During this time, the Plant paid the expenses for operating the Maine Plant, including capacity charges. The Plant, along with twenty-five other public entities (the "Secondary Purchasers"), withheld payments for service, including decommissioning fund charges. It is the position of the Secondary Purchasers that the voluntary shutdown of the Maine Plant constitutes a material, substantial breach of contract, and terminates their Contracts.

   On November 28, 1997, the Secondary Purchasers filed a Notice invoking the arbitration provision of their Contracts. Maine Yankee declined to arbitrate the dispute. On January 16, 1998, the Secondary Purchasers filed a motion to compel arbitration in the State of Maine Superior Court. On April 6, 1998, the Court denied the Secondary Purchasers motion to compel arbitration at this time.

   On December 15, 1997, Maine Yankee filed a Complaint with the Federal Energy Regulatory Commission (the "FERC"), asking the FERC to compel payments from the Secondary Purchasers. On January 22, 1998, the Secondary Purchasers filed an Answer to the Complaint requesting that the FERC dismiss the Complaint, and that FERC order Maine Yankee to proceed with arbitration.

NOTE F - COMMITMENTS AND CONTINGENCIES - Continued

During the latter part of 1998, the Secondary Purchasers and Maine Yankee engaged in negotiations that resulted in a settlement agreement. On January 25, 1999, Maine Yankee filed an Offer of Settlement with FERC that resolved all outstanding litigation between Maine Yankee and the Secondary Purchasers. The Offer of Settlement required the payment of all funds held in escrow and withheld since August 6, 1997 which was accrued as of December 31, 1998 (approximately $1,050,000). During 1999, the total amount held in escrow totaled $1,053,109. This amount was paid with an additional payment of $341,871 to Maine Yankee. As a result, Taunton's contractual obligations, including decommissioning, under existing Secondary Purchasers' Agreement with the Maine Yankee have been terminated.

2. The Plant has a contract with Vermont Yankee and certain of its Sponsors for 0.4602 percent of the output of the Vermont Yankee Plant. On January 6, 2000, Vermont Yankee Nuclear Power Corporation, Vermont Electric Power Company, and AmerGen Vermont, LLC, initiated a number of related proceedings before FERC all arising from the proposed sale of the Vermont Yankee Plant to AmerGen.

   The Plant and 21 other Massachusetts Municipals with similar Secondary Purchase Contracts for the Vermont Yankee output filed to intervene in FERC proceedings and subsequently filed a Protest and Request for Hearing, on February 14, 2000, with FERC as to the manner in which the Applicants above noted sought to effectuate the transfer and sale of the Plant. It is the position of the Plant and the other Massachusetts Municipals that the proposals before FERC would essentially transform their existing secondary purchase agreements, which expire in November 2002, and provide little if any benefits to the Plant. As a consequence, the Plant and other Massachusetts Municipals sought a hearing to investigate the many issues they raised in their Protest, and requested that FERC provide relief, including ordering protections to which they are entitled under their contracts and pursuant to the law; or in the alternative, to declare their contracts at an end. FERC has not yet acted on these matters.

   The Plant and the 21 Massachusetts Municipals have engaged in settlement negotiations with the Vermont Yankee Sponsors in late 1999 and continue by the Plant to do so. It is the further position of the Plant that the increased decommissioning amounts sought for service for Vermont Yankee, beginning January 1, 2000, are not permissible and it has objected to the collection of the increased amounts.

3. The Plant is involved in various legal matters incident to its business including note F #2, none of which is believed by management to be significant to the financial condition or the results of operations of the Plant.

NOTE F - COMMITMENTS AND CONTINGENCIES - Continued

4. The Plant is also involved in several proceedings relating to environmental matters. Although it is difficult to estimate the liability, if any, of the Plant related to these environmental matters, the Plant believes that these matters will not have a material adverse effect upon its financial condition or the results of operations.

NOTE G - PENSION PLANS

The Plant contributes to the City of Taunton Retirement System (the "System"), a public employee retirement system that acts as the investment and administrative agent for the City. All full-time employees participate in the System.

Instituted in 1937, the System is a member of the Massachusetts Contributory System and is governed by Massachusetts General Laws Chapter 32. Membership in the System is mandatory upon the commencement of employment for all permanent, full-time employees.

The System provides for retirement allowance benefits up to a maximum of 80% of a member's highest three-year average annual rate of regular compensation. Benefit payments are based upon a member's age, length of creditable service, level of compensation and group classification.

Members of the System become vested after 10 years of creditable service. A retirement allowance may be received upon reaching age 65 or upon attaining twenty years of service. The System also provides for early retirement at age 55 if the participant (1) has a record of 10 years of creditable service, (2) was on the City's payroll on January 1, 1978, (3) voluntarily left City employment on or after that date, and (4) left accumulated annuity deductions in the fund. Active members contribute either 5%, 7%, 8%, or 9% of their regular compensation depending on the date upon which their membership began. The System also provides death and disability benefits.

The System does not make a separate measurement of assets and the pension benefit obligation for the Plant. The pension benefit obligation is a standardized disclosure measure of the present value of pension benefits, adjusted for the effects of projected salary increases and step-rate benefits, estimated to be payable in the future as a result of employee service to date. The measure is intended to help users assess the funding status of the System on a going-concern basis, assess progress made in accumulating sufficient assets to pay benefits when due, and make comparisons among employers. The measure is the actuarial present value of credited projected benefits and is independent of the funding method used to determine contributions to the System. As of January 1, 1998 (the most current valuation date), the Plant's unfunded actuarial accrued liability is approximately $13,400,000.

NOTE G - PENSION PLANS - Continued

The Plant has established a separate Employees Retirement Trust Fund ("Trust Fund") for the financing of future pension payments. The market value of the net assets at December 31, 1999 and 1998 was approximately $13,150,000 and $14,198,000, respectively. These funds are invested in money market funds, fixed income securities including government and corporate bonds and other equity securities. The Plant has made no contributions to the Trust Fund in 1999 and 1998.

The Plant receives from the Trust Fund, over the next twenty-eight years, an amount equal to one hundred percent of the annual amortization of the unfunded pension liability.

The following represents the components of the Plant's recorded pension expense:

	December 31, 1999	December 31, 1998
Contributions to the System	$1,743,737	$1,719,400
Contributions from the Trust Fund	(1,238,553)	(1,178,721)
Recorded pension expense	$ 505,184	$ 540,679

Prior to 1993, the System's funding policy for the participating entities was not actuarially determined. The participating entities were required to contribute each fiscal year an amount approximating the pension benefits (less certain interest credits) expected to be paid during the year ("pay-as-you-go" method). Effective for fiscal year ends 1993 and beyond, the System has removed the "pay-as-you-go" method and will amortize the unfunded pension benefit obligation over thirty-two years. This change has been approved by Public Employees Retirement Association.

Accounting standards require certain related disclosures be made including the components of pension costs and the funded status of the System. The effect of omitting such disclosure on the accompanying financial statements has not been determined.

NOTE H - POST EMPLOYMENT BENEFITS

In addition to the pension benefits described in note G, the Plant provides post employment health care benefits to retirees that meet certain requirements. Retirees of the Plant under age 65 are eligible for the same health benefits as active employees, while retirees over the age of 65 are eligible for MEDEX. The costs of the benefits provided to retirees are borne 75% by the Plant, and 25% by the retirees.

The Plant is charged their prorata portion of the "pay-as-you-go" cost of benefits based on an allocation by the City done annually. For 1999 and 1998, the costs allocated to the Plant were approximately $512,000 and $451,000, respectively.

SUPPLEMENTAL INFORMATION

Report of Independent Certified Public Accountants
on Supplemental Information

Taunton Municipal Lighting Plant

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole of Taunton Municipal Lighting Plant for the years ended December 31, 1999 and 1998, which are presented in the preceding section of this report. The supplemental information presented hereinafter is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, is fairly stated, in all material respects, in relation to the basic financial statements taken as a whole.

Grant Thornton LLP

Boston, Massachusetts
February 29, 2000

Taunton Municipal Lighting Plant

OPERATING EXPENSES

Years ended December 31,

	1999	1998
POWER PRODUCTION		
Operation		
Supervision and engineering	$ 1,040,817	$ 789,391
Fuel	5,601,264	4,208,572
Labor and expenses	2,160,139	1,764,346
	8,802,220	6,762,309
Maintenance		
Supervision and engineering	442,445	350,515
Structures	140,363	131,927
Boiler plant	618,692	712,660
Electric plant	655,218	712,208
Miscellaneous	670,498	595,259
	2,527,216	2,502,569
Purchased power	16,223,401	16,139,758
Total power production	27,552,837	25,404,636
TRANSMISSION AND DISTRIBUTION		
Operation		
Supervision and engineering	226,319	266,470
Labor	4,443	21,244
Supplies and expenses	33,439	10,564
Meter expenses	298,563	205,349
Customer installation	5,265	22,616
Transmission by others	1,083,565	2,271,954
Overhead lines	123,371	144,610
Miscellaneous	456,391	218,508
	2,231,356	3,161,315
Maintenance		
Supervision and engineering	463,151	321,457
Lines - electric	1,550,412	1,508,958
Street lighting and signal systems	157,489	109,291
Meters	6,022	15,348
Structures and equipment	1,293	1,945
Line transformers	143,963	69,143
Station equipment	187,635	150,871
Miscellaneous	70,087	8,685
	2,580,052	2,185,698
Total transmission and distribution	4,811,408	5,347,013
Forward	32,364,245	30,751,649

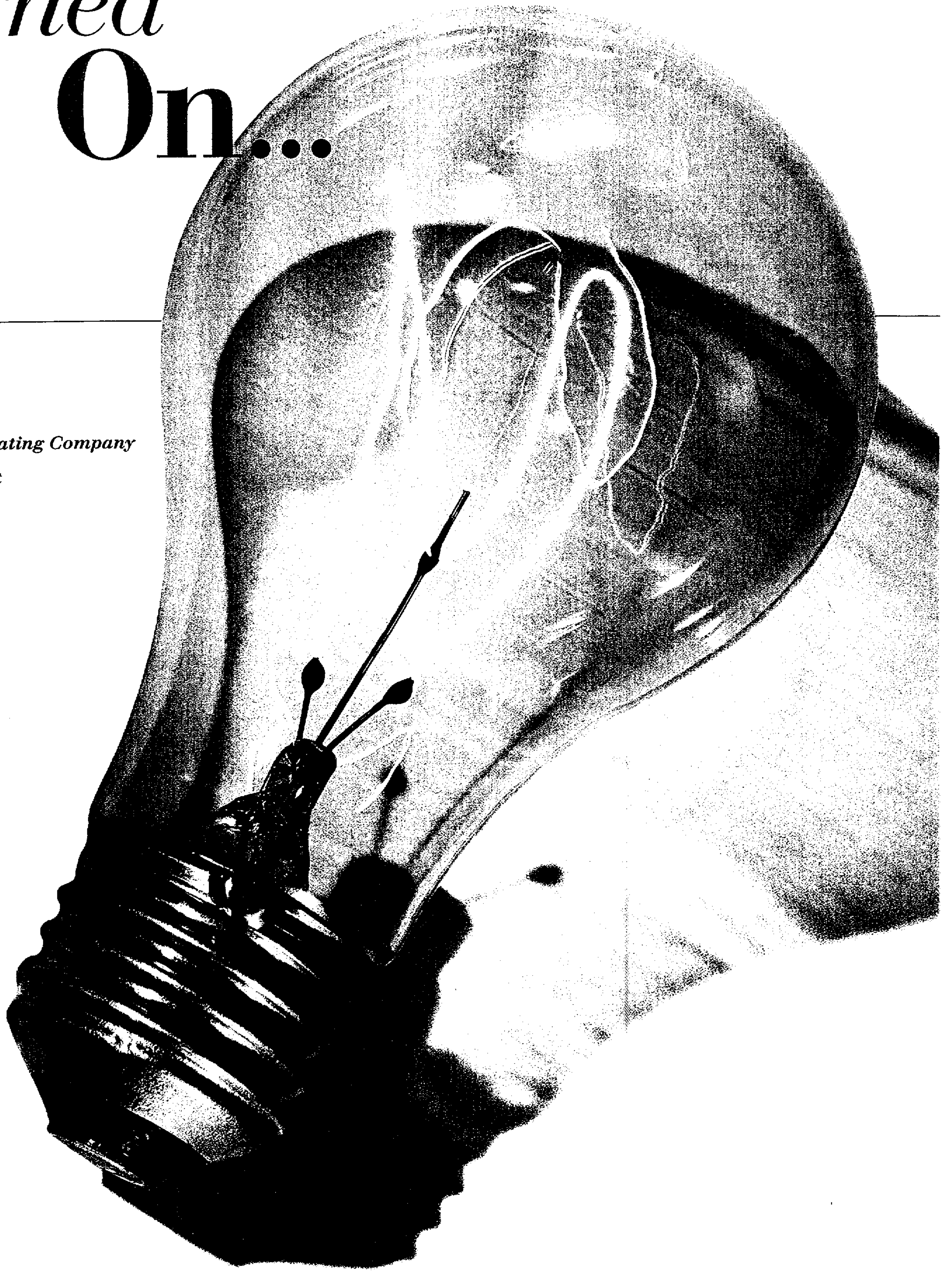
Taunton Municipal Lighting Plant

OPERATING EXPENSES - CONTINUED

Years ended December 31,

	1999	1998
Brought forward	$32,364,245	$30,751,649
CUSTOMER ACCOUNTING		
Meter reading labor and expenses	322,829	301,052
Accounting and collecting expenses	1,156,522	968,072
Uncollectible accounts	591,278	317,000
Advertising expense	107,816	23,004
Total customer accounting	2,178,445	1,609,128
ADMINISTRATIVE AND GENERAL		
Operation		
Administrative and general salaries	1,010,721	650,195
Office supplies and expenses	248,738	283,505
Outside services employed	298,010	539,104
Property insurance	220,615	190,567
Injuries and damages	233,593	229,488
Employee pensions and benefits	2,349,684	1,968,628
Miscellaneous general expenses	450,521	529,563
Transportation expenses	307,672	228,679
Transfer employee benefit expense	(2,168,443)	-
Regulatory commission expense	-	19
	2,951,111	4,619,748
Maintenance		
General plant	301,635	249,681
Office building	310,138	183,448
	611,773	433,129
Total administrative and general	3,562,884	5,052,877
DEPRECIATION AND AMORTIZATION	4,842,289	4,673,659
NUCLEAR EXPENSE	269,655	202,574
	$43,217,518	$42,289,887

Turned **On...**



The United Illuminating Company

1999 Annual Report

UI at a glance

Corporate Profile

The United Illuminating Company, headquartered in New Haven, CT, is an investor-owned regional distribution utility that provides electricity and energy-related services to more than 314,000 customers in the Greater New Haven and Greater Bridgeport areas.

UI has two primary non-regulated business units: American Payment Systems, Inc. (APS), and Precision Power Incorporated (PPI). APS provides automated payment systems to utilities and other companies across the nation. PPI has set out to be a leading provider of specialty electrical, telecom, and mechanical contracting and services to industrial, commercial and institutional customers throughout the Northeast and Mid-Atlantic Regions.

Financial Profile

(In thousands except per share amounts)	1999	1998	1997
Consolidated Highlights			
Operating Revenues	$679,975	$686,191	$709,029
Net Income	$ 52,224	$ 45,072	$ 43,457
Basic Earnings Per Common Share	$ 3.71	$ 3.20	$ 3.10
Diluted Earnings Per Common Share	$ 3.71	$ 3.20	$ 3.09
Return on Average Common Equity	11.45%	9.44%	10.45%
Book Value Per Common Share	$ 32.59	$ 31.74	$ 31.35
Dividends Declared Per Share	$ 2.88	$ 2.88	$ 2.88
Total Retail Kilowatt-hour Sales	5,652,050	5,452,332	5,365,347

Contents

We're
Turned On by
change

At The United Illuminating Company, we view change as a great opportunity, finding ways to use it responsibly and profitably. Throughout 1999, as we celebrated our century-old past, we discovered that the changes introduced by restructuring were throughways to stronger growth and higher earnings. This report once again affirms that UI is a company with the power to adapt and thrive. We're proving that change can be turned to advantage for our shareowners and customers.

Building foundations for growth

1995

UI initiates the "100 Million Challenge" by rallying employees to achieve the savings goal by the year 2000.

The "Power To Compete" program is launched – an umbrella theme for several programs designed to boost corporate performance, including the 100 Million Challenge, Unlimited Ideas and the new Corporate Identify Program.

1996

Anthony J. Vallillo appointed Group Vice President Client services. The veteran UI employee heads the wires company.

Through voluntary severance and retirement programs as well as employee attrition, UI's employee work force drops from an all-time high of 1,600 in 1990 to about 1,300.

1997

The Connecticut state legislature introduces the first in a series of bills designed to restructure the state's electric utility industry.

UI stock hits a five-year low of 24½, a reflection of the market's uncertainty over electric restructuring.

UI, Duke Energy Power Services, Inc. and Siemens Power Ventures, Inc. agree to build Bridgeport Energy – a multi-million dollar, 520-megawatt gas turbine facility at UI's Bridgeport Harbor Station.

UI begins preparing for the Y2K problem by assessing and analyzing the company's business and technical systems.

By refinancing $98.5 million in tax-exempt bonds, UI retires the remainder of its double-digit interest rate debt.

Impressed with the way UI is managed, businessman David Chase and his family invest in more than five percent of outstanding UI stock, becoming the company's largest shareowner.

1998

UI's Board of Directors elects Nathaniel Woodson as the new UI president and subsequently Chief Executive Officer. Woodson is the first of several key company leaders to be selected from outside the utility industry.

Dennis Dugan is named president of Precision Power, Inc., one of UI's non-regulated business units. Dugan joined the company from Burns and Roe, Inc., a New Jersey engineering, construction and management company.

UI agrees to sell its New Haven Harbor Station and Bridgeport Harbor Station generating units to Wisconsin-based Wisvest Corp.

UI common stock hits a ten-year high of 53¾.

1999

UI celebrates its Centennial Year, and begins its transition to January 1, 2000, the date when electric utility restructuring is slated to commence.

Nat Woodson succeeds Dick Grossi as UI's chairman of the Board of Directors.

UI completes the $272 million sales of BHS and NHHS to Wisvest-Connecticut, LLC.

In order to comply with Connecticut's new electric restructuring law, UI proposes to restructure itself into a holding company to be named UIL Holdings.

Due to regulatory uncertainty in the marketplace, UI's stock price reaches a 52-week low, closing at 38⅞.

UI scores points with prominent rating agencies. Moody's upgrades UI from "Baa3 with a positive outlook" to "Baa1 with a positive outlook." Standard & Poor's moves UI from "BBB- with a positive outlook" to "BBB with a stable outlook." Likewise, Duff and Phelps boosts its rating from BBB to BBB+.

UI President and CEO Nat Woodson rings the closing bell at the NYSE to mark the anniversary of UI's founding: June 16, 1899.

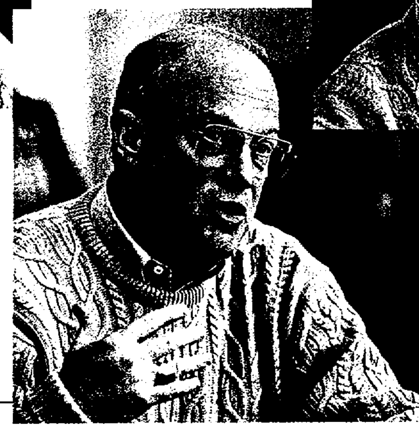
Paul Rocheleau is named president of American Payment Systems, Inc., one of UI's non-regulated businesses. Rocheleau joined APS earlier this year from Bloomingdale's by Mail, Ltd., where he was Vice President Finance and CFO.

All of UI's systems and equipment are confirmed as 100% Year 2000 ready. Morgan Stanley Dean Witter reinitiates coverage of UI stock with a neutral rating.

UI successfully completes all of its restructuring dockets with the DPUC. The company's workforce now totals 1239, with one-third in non-regulated businesses.

UI stock price closes the year at 51⅝.

Nathaniel D. Woodson



Dear shareowners:

The year 1999 was energizing every way you look at it.

It was a year in which we achieved near-record earnings in the face of the most significant change in our 100-year history – the restructuring of Connecticut's electric utilities.

It was a year when we fulfilled the need for a 10 percent electric rate reduction and took steps necessary to emerge stronger in terms of returns and growth potential.

And it was the year we affirmed our ability to recover capital invested in the pre-restructuring era while reducing uncertainty about our ability to evolve and grow our company for the benefit of shareowners and customers alike.

When industry restructuring legislation was enacted in 1998, UI made a number of strategic moves that has given us a distinct advantage. As we exited the electric generation business, we used the proceeds from asset sales to strengthen our balance sheet. This has significantly improved our credit rating.

The end of our role as an electric generation company gave us the opportunity to focus on and augment our strengths – first, as a reliable and responsive energy distribution company and second, as a provider of energy-related services. Quality of service with reduced rates, is the competitive need identified by the vast majority of our customers. Our sharpened focus has allowed us to capitalize on this need and become more valuable to those we serve.

One essential component in building our customer base has always been economic development. Rather than diminish our commitment to this pursuit, restructuring has underscored its importance. Likewise, the changes of 1999 have brought us down a path familiar to us in our 100-year history – the path of opportunity. In taking this path, we have rarely been disappointed. That's as true today as it was during a time when we were a fledgling electric company, in a fledgling industry.

We generated strong cash flow and earnings.

Impressive earnings from cost reductions and load growth in 1999, and the results of regulatory restructuring decisions eased concern about UI's financial performance in the near future.

We've got the green light

Ever since "electric choice" became the word on the street, The United Illuminating Company has been primed for change. Our careful preparations helped us secure favorable regulatory decisions. We're now investing wisely in our regulated business and the profit centers of our future: non-regulated businesses and financial investments promising high returns.

In fact, we experienced a near-record high in earnings – \$52 million or \$3.71 per share, with our dividend covered three-and-one-half times by cash flow. We haven't seen earnings this high since 1992. As a result, UI remained a solid investment for our shareowners even as the regulatory winds shifted. Our stock price exemplifies investor confidence, ending the year at 51⅜. Over the past three years, UI provided a return of 29 percent – a level twice that of the next best-performing Standard and Poor's utility stock.

1999 was the third year under our innovative rate plan, which allows an 11.5 percent utility equity return, accelerates asset recovery and reduces customer bills simultaneously. Under the plan, we accelerated amortization of pre-tax regulatory costs by \$17.5 million and provided additional price reductions to customers, bringing the total customer savings to 10 percent since December 1996.

Through generation asset sales and debt reduction, we freed up the capital necessary to fund our investment initiatives. This puts us in the enviable position of being at the ready when opportunities arise. We're taking a dynamic, yet balanced, approach to growth.

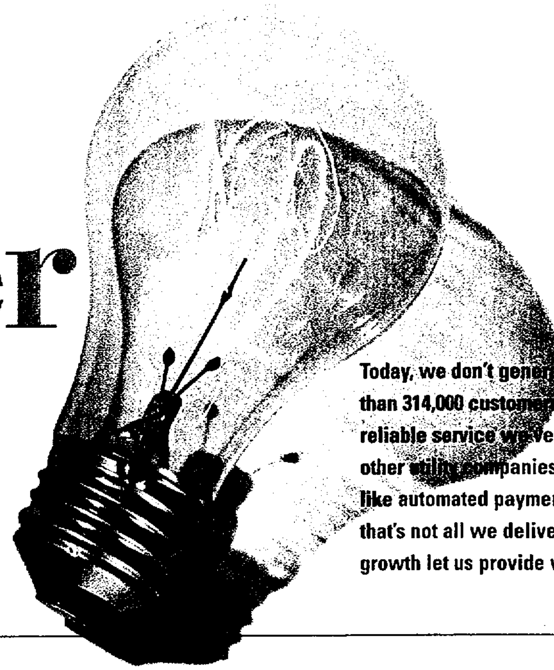
Growth fueled by ample reserves.

In 1999, we redirected our resources toward growth. And we did so with a base of solid dividends.

As we head toward a future of new growth opportunities, we can achieve a sustainable rate of earnings growth without veering toward unmanaged risk. And this differentiates us sharply from other companies that must grow at a much greater rate to yield the desired results for their shareowners. To redefine ourselves as a growth-oriented company, we need only create new earnings in the range of \$15 to 20 million over the next five years – not a daunting task for a company with our skills, size and resources. With diligence and attention to detail, we can readily achieve this goal.

Our strategic preparation for the 1999 regulatory restructuring decisions energized our organization and allowed us to survive with a solid base of regulated operations. Our strong regulated business team has re-defined the wires business role and laid the groundwork for where we are today. Our diligent preparation led to responsible decisions by the state Department of Public Utility

We deliver



Today, we don't generate electricity. We deliver it. More than 314,000 customers depend on us for the responsive, reliable service we've provided for over a century. And other utility companies come to us for value-added services like automated payment and power system expertise. But that's not all we deliver. Dividend stability and earnings growth let us provide value to our shareowners.

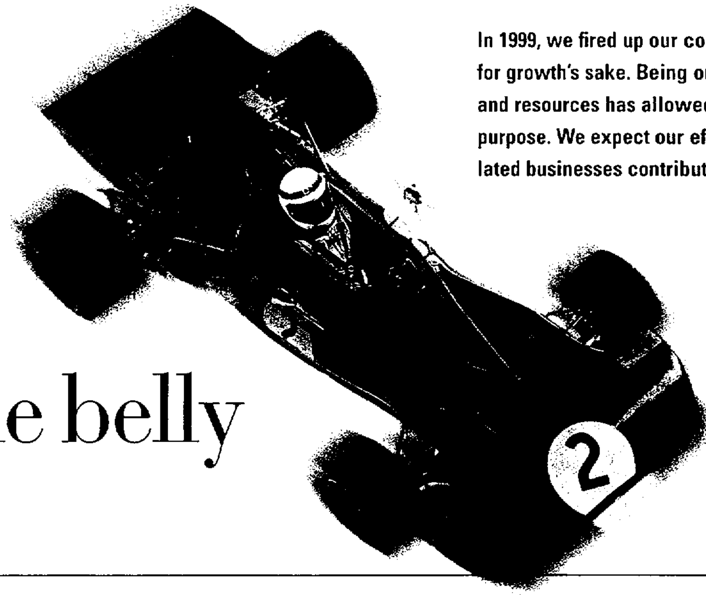
Control (DPUC) in every major proceeding, including those involving stranded cost recovery and the standard offer, which sets our customer price components over the next four years.

Investing wisely in the right management has already paid dividends in our principal non-regulated units. One of these, American Payment Systems, Inc. (APS) is the nation's leading supplier of walk-in bill payment processing services to the utility industry. Last year, it processed 81 million payments and handled more than $8 billion. Our other principal non-regulated business, Precision Power, Inc. (PPI), has set out to become a leading provider of specialty electrical, telecom and mechanical contracting and services to industrial, commercial and institutional customers throughout the Northeast and Mid-Atlantic regions. As part of the growth strategy for PPI, we are incurring near-term expense to prepare it to manage profitable growth in the future. In 1999, PPI acquired Allan Electric Company of New Jersey and will acquire other strategically relevant companies to complement the PPI businesses as we move through 2000. Both Allan Electric and APS were profitable in 1999, and we anticipate increased profitability in 2000.

The goal of expanding our earnings base sent us into related growth centers in 1999. We invested in promising non-regulated businesses. One of these is the most advanced combined cycle gas plant in Connecticut, built by Duke Energy and Siemens Power, in which UI now holds one-third interest on a non-operating basis. We don't sell the energy from this plant, we're simply an investor. And we're actively seeking other purely financial investments of commensurate profit potential. For instance, we're working with a project developer to assess the growth potential of a high voltage DC transmission cable that will connect New England to Long Island as an alternate energy supply path. And, we're carefully making modest investments in new entrepreneurial start-ups in our region to benefit you, our shareowners, and the region we serve.

Our expectation for these non-regulated businesses over the next three to five years is that they will yield at least 20 percent of our total earnings, which their performance to date more than justifies. This expectation is bolstered by our plans to restructure UI as a holding company to be known as UIL Holdings Corporation. The DPUC and Securities and Exchange Commission have cleared

In 1999, we fired up our commitment to growth – but not growth for growth's sake. Being on the right track with people, planning and resources has allowed us to pursue our goals with vigor and purpose. We expect our efforts to soon pay off, with non-regulated businesses contributing 20% or more of our total earnings.



Fire in the belly

our plans and your recent involvement in this process will allow us to move forward with our plans. The regulated and non-regulated businesses will be separated under the holding company which will provide the non-regulated businesses with a better platform for growth.

Turning corners with the right people already in place.

Over the past 16 months, UI had been carefully building its managerial team to meet the demands dictated by change. Our role as a widely-recognized leading energy distributor, our promise as a holding company of growth-oriented business units, and the changes we foresaw in our industry have all been deftly managed by a team of enormous insight and foresight. As the year 2000 dawned, we entered in a state of managerial resolution, not transition. We have a team of leaders who have proven that change can always be turned to our advantage.

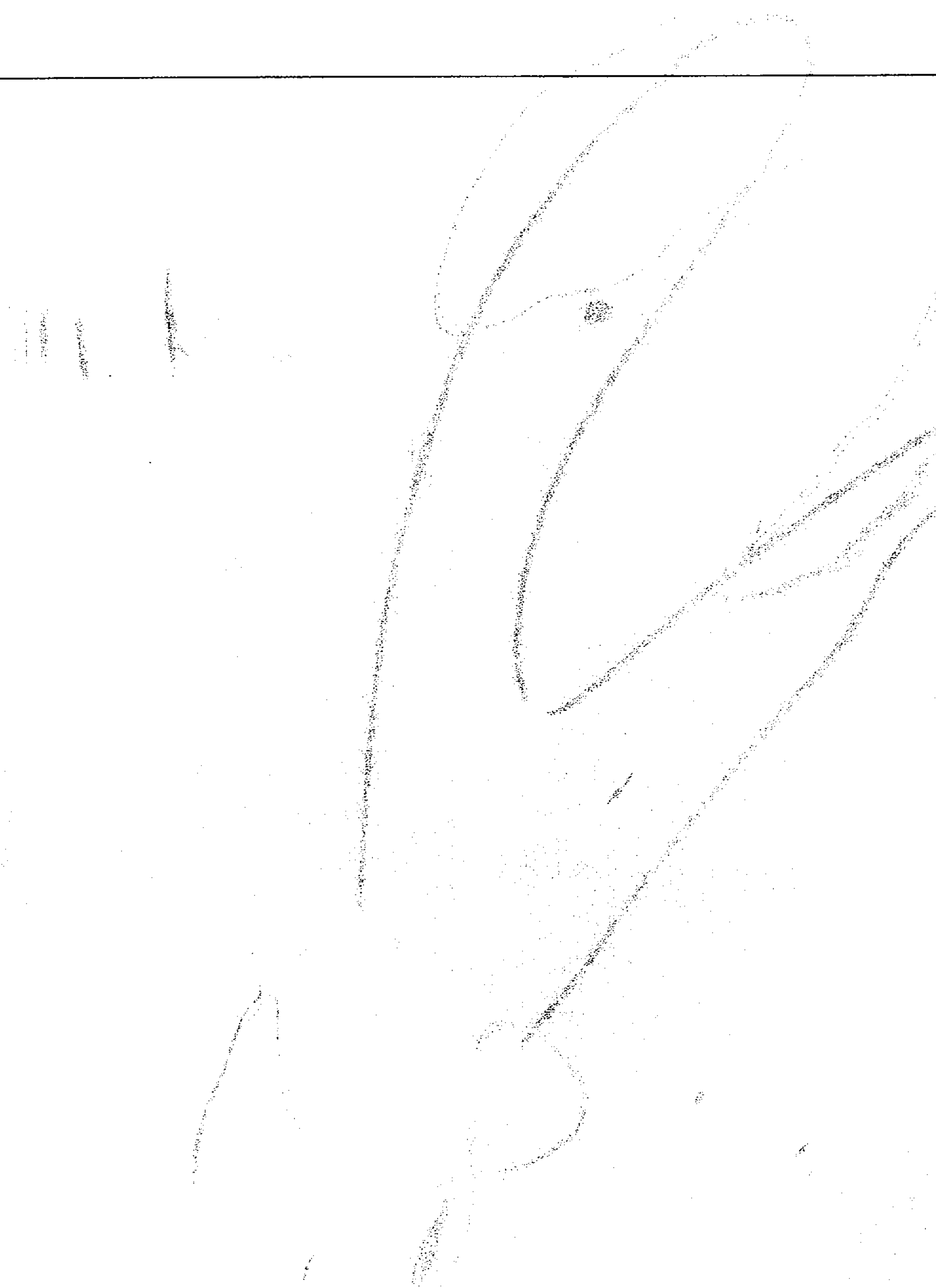
Clearly, we have emerged from restructuring all the stronger, having prepared for the inevitable with a plan carefully balanced by prudence – as evidenced by our earnings – and vision – as evidenced by the full breadth of our future potential.

We've proven ourselves to be a solid investment on the one hand and, on the other, a company willing to seize the moment, ruling out no relevant opportunity that offers us real potential to grow in value to our shareowners.

Every manager and team leader at UI has committed to take this company and run it as hard and intelligently as we can. That is our continuing promise, and the results to date confirm that our company consistently delivers on its promises.

You can be confident that we will honor that high principle in the future, and we thank you for the enthusiastic support you have shown us.

Nathaniel D. Woodson,
Chairman, President and Chief Executive Officer



The broader brushstrokes of 1999 define UI as a company that has made the leap into the new millennium with preparedness and optimism. Financially and structurally speaking, the prospects for the future could not be brighter. But the finer points of this transition and its future implications merit a closer look. On the following pages, Nathaniel Woodson (Chairman, President and CEO) and Robert Fiscus (Vice Chairman and Chief Financial Officer) voice some of the answers to questions they have probed over the past 12 months.

Small is beautiful

The beauty of being a small utility with large cash sources is we don't need to be a corporate giant to perform as a first-rate investment. Large-scale higher-risk ventures simply aren't necessary. With additional earnings of only $15 to $20 million over the next three to five years, we can redefine ourselves as a growth-oriented company with high shareowner value. Since we're adept in responding to change, that's achievable.

Robert L. Fiscus

Nathaniel D. Woodson

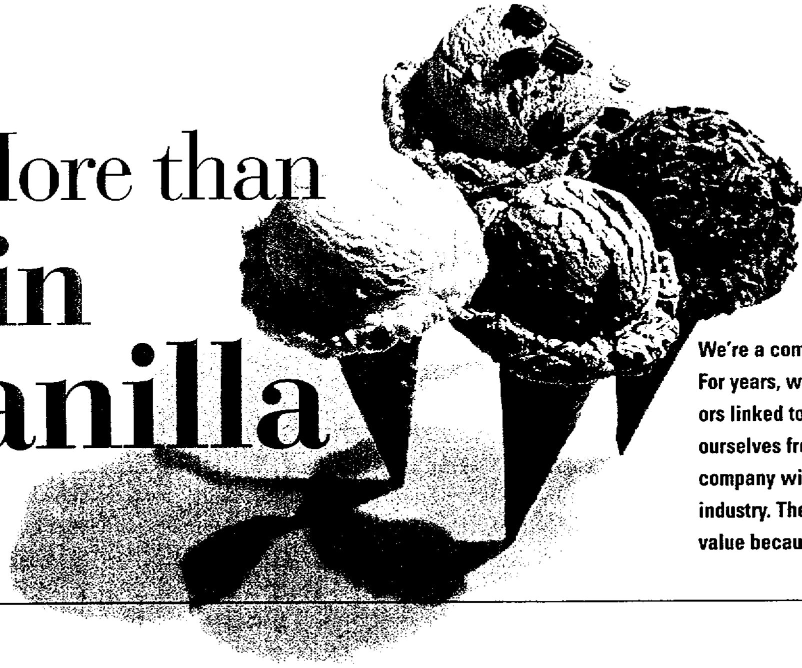
Q: Pinpoint exactly how the UI of the year 2000 differs from the UI of a year ago.

A: Woodson: In 1999, we celebrated our hundredth year of business by implementing our operational restructuring plan. Now that our plan is in place, we are no longer responsible for generating electricity, as we were for a century. We sold our electric generation operations. Today, our primary regulated business is energy delivery. We entered into an agreement with Enron Corporation to supply the full four years of our standard offer service, an arrangement that we are confident will benefit all concerned. We deliver electric services to our customers at prices ten percent below those of 1996, with a renewed commitment to reliable, responsive service. And we operate energy-related non-regulated business units with the goal of growing our earnings base. So the UI of the year 2000 has evolved beyond a small, integrated electric utility company toward a company comprised of energy-related businesses – developing far greater shareowner value than ever before. Adding to shareowner value is our solid dividend, something that isn't changing.

Q: Will the fact that UI no longer generates electricity alter its emphasis on customer service?

A: Woodson: Absolutely not. Whatever the future may hold, we will not lose touch with the relationships we've built with our residential, commercial, industrial and institutional customers. First and foremost, we will maintain a reliable, responsive energy delivery system and fully retain our focus on customer service. Even as we compete for the hearts and minds of investors on Wall

More than plain vanilla



We're a company that's always been wired for change. For years, we've extended our reach toward new endeavors linked to our core business. Today, we're transforming ourselves from a plain vanilla utility to a growth-oriented company with a diverse menu of services offered to our industry. The UI of today is delivering higher shareowner value because we've changed. And prospered.

Street, we will devote ourselves to the people who think of us primarily as the company that delivers their electric service. And that includes boosting economic development in our region to attract new businesses, on top of retaining the businesses we now have.

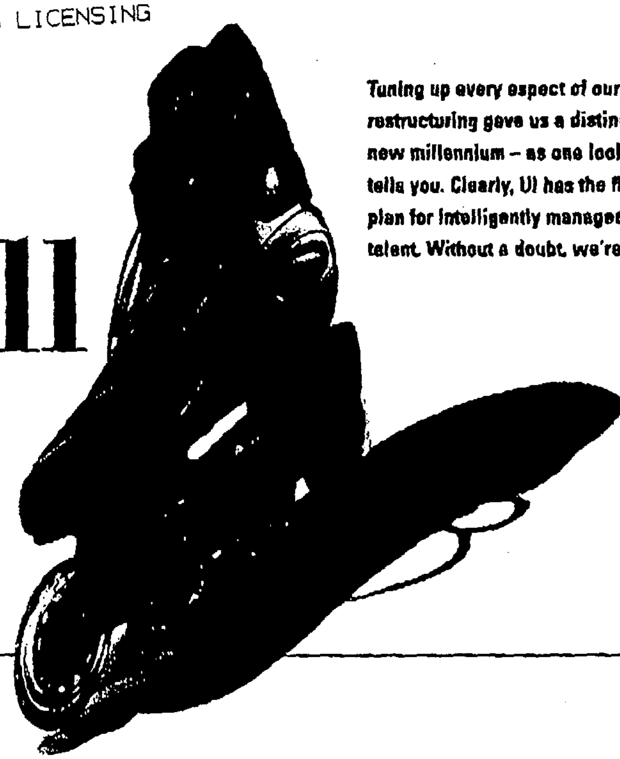
Q: What advantages do you see in being a small utility company with a large cash flow, and how well does this bode for your shareowners?

A: Fiscus: Everyone at UI has heard me say that we don't have to reinvent Microsoft or GE to create a substantial growth platform. We can readily sustain growth at a relatively modest re-investment level. Within a few years of laying down the markers and creating a track record, we will prove to the financial community that we have made the transition from small-and-well-managed to well-managed-and-growing-strong. And this is supported by the fact that new earnings of only $15-20 million over the next five years should be sufficient to get us there. That's not an onerous task for us. It's realistic and achievable. We have already laid the groundwork via investments that are much more favorable to our shareowners. If you compare us to larger utilities that have to produce growth of hundreds of millions of dollars a year – often by assuming great risk – you'll conclude that investing in UI is a much different ball of wax. We really can propel this company forward without having to take outlandish risks. To our shareowners, that presents a distinct advantage.

Q: Does your top management possess the skill sets necessary to address the day-to-day challenges while transforming UI into a growth company?

A: Woodson: I think we have a particularly effective group running our regulated and non-regulated businesses. Our financial team has certainly proven its mettle, as evidenced by our balance sheet and the way in which they've worked with the equity and debt sides of the house. And we've populated all of our ventures with the right people – both company veterans and new folks – over the last two years, making the time-and-money investment where it counts most. It's paying off handsomely. We now have people with the confidence to get on with reinvesting our cash flow, people who are very turned on and very motivated toward benchmarking our performance against that of our peers. At the same time, we have a team with the professional rigor and incentive to motivate our people toward making

Ready to roll



Tuning up every aspect of our operations in response to restructuring gave us a distinct advantage at the start of a new millennium – as one look at our price/earnings ratio tells you. Clearly, UI has the financial mettle to pursue our plan for intelligently managed growth. And the managerial talent. Without a doubt, we're in sync and on top.

things happen daily. Right now, I would say we're a company fueled both by careful planning and conscientious people. People with enough fire in the belly to keep us roaring down the track.

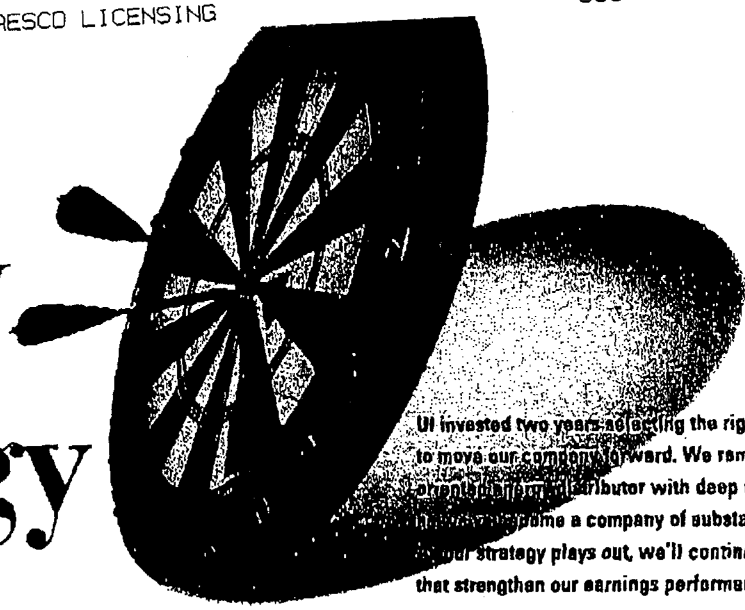
Q: In three to five years, what changes do you expect to see take place within your company in terms of its non-regulated growth ventures?

A: Fiscus: As we head down the road, I think you'll see a company with a much stronger balance between its regulated and non-regulated businesses. That will be quite a transformation. At the very minimum, we expect our non-regulated businesses to be producing at least 20% of UI's total earnings over the next three to five years. Each of our business unit leaders has ample incentive to exceed this goal and achieve maximum revenue and profit growth. Another big change will arise from the fact that our top management has significantly increased its share-owning requirements. As we push ourselves hard to achieve sustained business growth, we will do so ever mindful of our shareowners' best interests. It will all add up to a UI that is charging forward, creating value and playing a key role in restructuring the New England energy delivery system.

Q: What are your company's primary competitive advantages?

A: Woodson: Three factors. The first is that we know how to work within the communities we serve. I'm not cheerleading when I say that UI is highly respected in regional business and community circles. That's been borne out by customer surveys. Customers tell us that they like knowing a company that is really focused on them as customers and not just as rate-payers. The second distinguishing factor is that our organization has enthusiastically embraced change. We've changed our processes and how we work as a team in response to restructuring, which we have always viewed as an opportunity rather than as a threat. The final distinction between UI and our competitors is that we have a very strong and predictable cash flow, making it possible to transform ourselves into a dynamic growth company with relatively few growing pains.

Sharply focused strategy



UI invested two years selecting the right strategy and people to move our company forward. We remain a customer-oriented energy distributor with deep community ties even as we become a company of substantial growth potential. As our strategy plays out, we'll continue to make decisions that strengthen our earnings performance.

Q: Do you anticipate a merger or acquisition in the future of The United Illuminating Company, or have you ruled out the possibility?

A: Woodson: Priority one with UI is what serves the best interests of our shareholders. To be honest, we looked intently at whether we could become involved in the consolidation of Connecticut's three gas distribution companies. But once we saw the price levels being offered by larger players, we quickly ruled it out. We're not going to enter into a deal simply to prove we have the financial muscle to acquire. Fully respecting the interests of our shareowners demands restraint. Yet, just as we don't intend to get carried away by the euphoria of deal-making, we also have a fiduciary obligation to evaluate opportunities for mergers if they arrive. We have a sense of what we're worth and can judge M&A issues accordingly. We won't rule anything out if we see real potential in terms of shareowner value. That remains our criterion for any future scenario.

Q: UI is a Connecticut utility company, yet your geographic reach extends well beyond New England. Explain how this might influence your future investments.

A: Fiscus: We find it gratifying that, as a regulated company serving a region of 300 square miles, one of our non-regulated businesses – a walk-in payment services company called American Payment Systems – operates in the entire United States. And another of our businesses, Precision Power Inc., an energy services company, will serve a territory extending from Boston to Washington, D.C. However, most of our future investments are likely to be based in the New England area, because that is our strategic comfort zone. We know New England through and through, and we have unique opportunities to participate in energy-related projects here.

Q: For investors and analysts, what would you emphasize as the strongest reasons to buy into UI today.

A: Woodson: UI has a strong management team with a record of purposeful planning, strategic foresight and smart decisions that have paid off handsomely for all concerned. We're a company that can achieve sustainable, significant earnings growth without making large, wild bets. And we've come through a period of transition in a state of strength, resolve and stability. The integrity of our people and our company has once again been confirmed by how well we handle change. To a shareowner, all of those factors should be very encouraging. And, we hope, very convincing.

Summary Results of Operations

I. The 5 Year Rate Plan ("The Rate Plan")

The Company's principal regulated electric utility business is operating under a five-year Rate Plan that began in 1997 and goes through 2001. The Rate Plan allows for an equity return of 11.5% on rate base equity and a sharing mechanism that allows the Company to earn above 11.5% if operating margins improve over anticipated levels. The Rate Plan also provides for annual increases in accelerated amortization, although earnings need to be at least 10.5% for these charges to be taken.

II. Year End 1999 Consolidated Results Compared to 1998 Consolidated Results (as restated)[1]

	12/31/99	12/31/98	1999 vs. 1998
Total Operating Revenue	$679,975	$686,191	$ (6,216)
Total Sales Margin	$493,395	$510,608	$(17,213)
Total Earnings for Common Stock	$ 52,105	$ 44,892	$ 7,213
Total EPS	$ 3.71[2]	$ 3.20	$ 0.51
EPS from one-time items	$ 0.04	$ (0.21)	$ 0.25
EPS from operations	$ 3.67	$ 3.41	$ 0.26
gWh Sales	5,652	5,452	200

(1) During the third quarter of 1999, the Company restated its financial statements for 1998, 1997 and 1996 for matters related to the timing of American Payment Systems (APS) agency collection reserves and for certain loss factors that affect the calculation of unbilled revenues.

Earnings per share restatement is as follows:

For the year ended December 31:	1998	1997
Earnings per share, as originally reported	$3.00	$3.27
Earnings per share, as restated	$3.20	$3.09

(2) Earnings from operations before earnings "sharing" were $5.09 per share, 39% higher than 1998.

III. Earnings Per Share for 1999 Compared to 1998

EARNINGS PER SHARE FROM OPERATIONS – 1999 vs. 1998

Total earnings may fluctuate due to various non-recurring items. Looking at "earnings from operations," which exclude non-recurring items, is a useful way to evaluate year-to-year trends and build expectations for the future years.

1999 earnings from operations were $3.67 per share, up $.26 per share from 1998. The increase was largely due to increased "real" retail sales growth of approximately 3.2%.

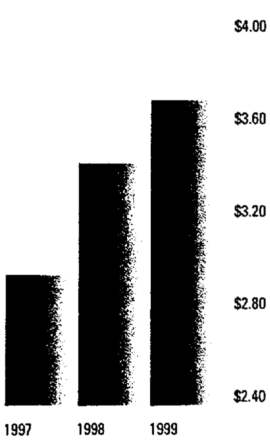
1999 earnings from operations, before earnings "sharing" were $5.09 per share, which was $1.44 per share or 39% higher than 1998. "Sharing " reduced 1998 earnings from operations to $3.67 per share.

TOTAL EARNINGS PER SHARE – 1999 vs. 1998

Total earnings per share for 1999 were $3.71, up $.51 per share from the 1998 level of $3.20. Earnings in 1998 and 1999 were affected by various non-recurring items that, if not segregated, produce a view of recent earnings trends that is different from the view provided by earnings from operations. The non-recurring items were:

1999 – An increase of $.04 per share for a purchased power refund (Refund was $.12 per share offset by $.08 per share from sharing.)

1998 – Charges related to a property tax settlement with the City of New Haven, offset by a refund of prior period transmission charges, accounted for a net $.21 per share decrease in earnings.



Earnings Per Share From Operations

IV. Utility Earnings from Operations–1999 vs. 1998

• Total retail revenue increased by $8.0 million, which was offset by increased revenue-based taxes of $.5 million and increased fuel and energy expenses of $20.7 million (primarily due to purchased energy) resulting in a reduction in total retail margin of $13.2 million.

• Net wholesale margin decreased by $10.4 million in 1999 due to lower wholesale sales. Other operating revenues, which include transmission-related revenues, increased by $6.4 million.

• Operating expenses for operations, maintenance and purchased capacity charges decreased by $5.7 million in 1999 compared to 1998, principally due to reduced capacity expenses associated with Connecticut Yankee and reduced operation and maintenance expenses because of the April 1999 sale of the fossil generating stations. These decreases were offset by increases in transmission expense, site remediation costs and nuclear costs.

• Depreciation expense, excluding accelerated amortization, decreased by $12.4 million in 1999, primarily due to the generation asset sale.

• Interest charges decreased by $12.8 million for the regulated business in 1999, partly offset by an increase of $3.5 million in interest charges for non-regulated business units.

V. Non-Regulated Business Earnings from Operations

• Non-regulated businesses, after parent allocated interest but before income taxes, lost $3.8 million in 1999 compared to $2.0 million in 1998.

American Payment Systems earned $2.6 million (before tax) in 1999, compared to $1.6 million in 1998.

Precision Power, Inc. lost $5.1 million (before-tax) in 1999, compared to a loss of $2.4 million in 1998, reflecting increased infrastructure costs and lower than anticipated contract margins.

United Bridgeport Energy lost $.1 million (before-tax) in 1999, as a result of a 2nd quarter shutdown to allow for construction of the 2nd phase of the project and additional unscheduled outages and higher gas prices.

Other non-regulated business units lost $1.2 million in 1999, compared to a similar loss in 1998.

VI. Looking Forward to 2000

• Earnings at 11.5% will generate $3.25-$3.35 per share.

• Operation of nuclear units (until they are sold) will contribute to above estimate.

• Sharing greatly reduced from 1999 levels due to mandates in legislation; Shareowner retained earnings is not expected to be more than $.10-$.15 per share.

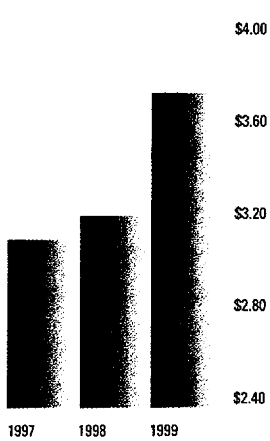
• Non-regulated business units expected to contribute to earnings as follows:

American Payment Systems: $.10-$.15 per share.

United Bridgeport Energy: $.10-$.15 per share.

Precision Power, Inc.: ($.05)-$0 per share.

• Contingent upon normal weather and normal operation of nuclear units, the Company earnings are expected to be $3.60-$3.80 per share.



Total Earnings Per Share

Condensed Consolidated Statement of Income

This statement is a summary of the Company's operating performance that shows the Company's revenues and expenses that result in the "Balance for Common Stock," the earnings for all shareowners.

For the Years Ended December 31, 1999 and 1998 (In Millions of Dollars Except Per Share Amounts)	1999	1998
Operating Revenues	$ 680	$ 686
Fuel and energy expense	162	152
Sales-related taxes	24	23
Sales Margin	494	511
Operation expenses	242	252
Depreciation and amortization	94	96
Non-recurring (income) and expense	(3)	11
Other (income) and expenses	(1)	–
Interest expense	43	52
Income Before Income Taxes	119	100
Income taxes for operations	66	59
Non-recurring income taxes	1	(4)
Net Income and Income Applicable to Common Stock	$ 52	$ 45
Average Number of Shares Outstanding	14	14
Earnings per Share – Basic and Diluted	$3.71	$3.20

Includes operation, maintenance, purchased capacity and property and payroll taxes

Includes $13 million of accelerated amortization of regulatory assets in 1999 and $13 million of accelerated amortization of conservation costs in 1998

The Company's refinancing program and strong cash flow help to reduce interest expense

Non-recurring charges for 1999 reflect a transmission expense refund and for 1998 includes $14 million for a property tax settlement offset by $3 million for a one-time refund

	1999	1998
Retail Operating Revenue	$ 640	$ 632
Other Operating Revenue	16	9
Retail fuel and energy expense	138	117
Sales-related taxes	24	23
Retail Sales Margin	$ 494	$ 501
Wholesale Operating Revenue	$ 24	$ 45
Wholesale fuel and energy expense	24	35
Wholesale Sales Margin	$ –	$ 10

Reflects lower sales in wholesale market

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1999.

Condensed Consolidated Balance Sheet

This statement reports the Company's total assets (what we own and what is owed to us), liabilities (what we owe others, now and in the future, and capitalization (amounts invested in or loaned to the Company, at the end of the year.

December 31, 1999 and 1998 (In Millions of Dollars)	1999	1998
Assets		
Utility Net Plant at Original Cost	$ 475	$1,172
Construction Work in Progress	26	34
Nuclear Fuel	21	20
Other Property and Investments	132	38
Current Assets		
Cash and temporary cash investments	68	125
Customer accounts receivable, net and accrued utility revenues	81	75
Other	70	105
Total	219	305
Deferred Charges	15	11
Regulatory Assets	910	361
	$1,798	$1,941
Capitalization and Liabilities		
Capitalization		
Common stock equity	$ 458	$ 445
Preferred stock	–	4
Mandatorily redeemable securities of subsidiary	50	50
Long-term debt – net	518	665
Total	1,026	1,164
Noncurrent Liabilities	245	110
Current Liabilities		
Current portion of long-term debt	25	66
Notes payable	17	87
Accounts payable	105	103
Other	61	70
Total	208	326
Regulatory Liabilities	52	18
Deferred Income Taxes	264	321
Other	3	2
Commitments and Contingencies	–	–
	$1,798	$1,941

Reflects transfer of $512 million of plant in service to regulatory asset

Includes inventory, prepayments and receivables for interest and subsidiaries' billings

Principally unamortized debt issuance costs

Future amounts due from customers through the ratemaking process, principally to collect future income taxes and stranded costs

Includes obligations for purchase power contracts Connecticut Yankee, pensions and nuclear decommissioning costs

Includes dividends payable, taxes accrued and interest accrued

Future amounts owed to customers through the ratemaking process

Future tax liabilities owed to taxing authorities from future customer revenues

Shareowner's "book" value
1999: $32.59 per share
1998: $31.74 per share

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1999.

Condensed Consolidated Statement of Cash Flows

This statement summarizes cash inflows and outflows during the year from operating, investing, and financing activities.

For the Years Ended December 31, 1999 and 1998 (In Millions of Dollars)	1999	1998
Cash Flows From Operating Activities		
Net income	$ 52	$ 45
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	96	101
Deferred income taxes	(53)	3
Amortization of nuclear fuel	8	7
Other non-cash income items	(3)	(1)
Subtotal	100	155
Cash used for working capital changes	(2)	(42)
Cash Provided by Operating Activities	98	113
Dividend payments	(41)	(41)
Cash (used for) provided by short term borrowings	(70)	49
Cash used for debt and equity redemptions	(223)	(222)
Cash provided by debt/equity issuances and borrowings	26	202
Cash provided by investments in debt securities	5	9
Cash used for investment in unregulated business	(88)	–
Cash provided by sale of generation assets	271	–
Cash used for capital expenditures	(35)	(38)
(Decrease) increase in Cash and Temporary Cash Investments	(57)	72
Cash Balance at Beginning of Period	125	53
Cash Balance at End of Period	$ 68	$125

These amounts are included in the calculation of net income, but do not represent cash outflows

Changes in working capital higher in 1998 due to payment of current obligations and the end of a fuel lease arrangement

Repayment of prior years' investment in our own debt securities

	1999	Revised 1998
Cash Available from Earnings to Pay Interest Charges (A)	$138	$164
Annual Cash Interest Charges (B)	40	51
Total Debt (C)	543	731
Cash Coverage Ratio (A) / (B)	3.5	3.2
Cash Available to Total Debt (A-B) / (C)	18%	15%

	1999	Revised 1998
Cash Provided by Operating Activities less Dividend Payments	$57	$72
Capital Expenditures	(35)	(38)
Difference	$22	$34

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1999.

Financial and Stock Data[1]

INCOME AND DIVIDEND DATA

Year	Sales Margin $ mil	Sales Margin $/share	Pretax (fed.) Net Income $ mil	Pretax (fed.) Net Income % of s.m.	Balance for Common $ mil	Basic Earnings per Share $	Diluted Earnings per Share $	Dividend Declared Share $	Payout Ratio %	Yield on Average Price %
1995	525	37.25	92	17.5	51	3.60	3.59	2.82	78.3	8.5
1996	540	38.30	74	13.8	41	2.88	2.87	2.88	100.0	8.1
1997	504	36.06	72	14.3	43	3.10	3.09	2.88	92.9	8.2
1998	511	36.42	84	16.4	45	3.20	3.20	2.88	90.0	6.0
1999	494	35.11	103	20.9	52	3.71	3.71	2.88	77.6	6.2
5 Yr. Avg.	515	36.63	85	16.6	46	3.30	3.29	2.87	87.8	7.4

COMMON SHARE DATA

Year	Closing Price Range $ High	Closing Price Range $ Low	Closing Price Range $ End	Price Earnings Ratio High	Price Earnings Ratio Low	Price Earnings Ratio Close
1995	38 1/2	29 1/2	37 3/8	10.7	8.2	10.4
1996	39 3/4	31 3/8	31 3/8	13.8	10.9	10.9
1997	45 15/16	24 1/2	45 15/16	14.8	7.9	14.8
1998	53 3/4	42 5/8	51 1/2	16.8	13.3	16.1
1999	53 3/16	39 5/16	51 3/8	14.3	10.6	13.9
5 Yr. Avg.	46 1/4	33 1/2	43 1/2	14.1	10.2	13.2

COMMON SHARE DATA (Cont'd)

Quarter ended	Closing Market Price $ 1999 High	1999 Low	1999 End	1998 High	1998 Low	1998 End	1997 High	1997 Low	1997 End	Trading Volume in Thousands 1999	1998	1997
3/31	52 11/16	41 7/8	41 15/16	48 9/16	42 5/8	48 3/8	32 5/8	24 1/2	26 1/8	1,698	2,874	4,990
6/30	44 11/16	39 5/16	42 7/16	51 15/16	46 15/16	50 5/8	30 7/8	24 1/2	30 7/8	3,034	2,631	4,660
9/30	50 11/16	43 1/8	48 3/8	53 9/16	49	52 1/4	37	31 1/2	36 7/16	2,784	2,183	4,032
12/31	53 3/16	47 15/16	51 3/8	53 3/4	48 1/16	51 1/2	45 15/16	37	45 15/16	1,663	1,382	2,710

QUARTERLY FINANCIAL INFORMATION

Quarter ended	Sales Margin $ mil. 1999	1998	1997	Pretax (fed.) Net Income $ mil. 1999	1998	1997	Basic Earnings per Share $ 1999	1998	1997	Dividends Paid per Share $ 1999	1998	1997
3/31	127	116	121	22	18	21	0.70	0.64	0.93	0.72	0.72	0.72
6/30	120	121	120	26	16	4	0.99	0.60	0.33	0.72	0.72	0.72
9/30	140	152	147	45	45	38	1.78	1.87	1.60	0.72	0.72	0.72
12/31	107	122	116	10	5	9	0.24	0.10	0.23	0.72	0.72	0.72

s.m. = Sales Margin; (fed.) = Federal

(1) Certain data for the years 1995-1998 have been restated.

Major Influences on Financial Condition

The Company's financial condition will continue to be dependent on the level of its utility retail sales and the Company's ability to control expenses, as well as on the performance of the non-regulated businesses of the Company's subsidiaries. The two primary factors that affect utility sales volume are economic conditions and weather. Total utility operation and maintenance expense, excluding one-time items and cogeneration capacity purchases, declined by 1.6%, on average, during the five years 1995-1999.

The Company's financial status and financing capability will continue to be sensitive to many other factors, including conditions in the securities markets, economic conditions, interest rates, the level of the Company's income and cash flow, and legislative and regulatory developments, including the cost of compliance with increasingly stringent environmental legislation and regulations.

On December 31, 1996, the DPUC completed a financial and operational review of the Company and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The DPUC did not change the existing retail base rates charged to customers, but the Rate Plan increased amortization of the Company's conservation and load management program investments during 1997-1998, and accelerated the amortization and recovery of unspecified assets during 1999-2001 if the Company's common stock equity return on utility investment exceeds 10.5% after recording the amortization. The Rate Plan also provided for retail price reductions of about 5%, compared to 1996 and phased-in over 1997-2001, primarily through reductions of conservation adjustment mechanism revenues, through a surcredit in each of the five plan years, and through acceptance of the Company's proposal to modify the operation of the fossil fuel clause mechanism. The Company's authorized return on utility common stock equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are to be utilized one-third for customer price reductions, one-third to increase amortization of assets, and one-third retained as earnings. As a result of the Rate Plan, customer prices were required to be reduced, on average, by 3% in 1997 compared to 1996. Also as a result of the Rate Plan, customer prices were required to be reduced by an additional 1% in 2000, and another 1% in 2001, compared to 1996. Retail revenues decreased by approximately 7.0% through 1999 compared to 1996 due to customer price reductions. The Rate Plan was reopened in 1998, in accordance with its terms, to determine the assets to be subjected to accelerated recovery in 1999. The DPUC decided on February 10, 1999 to subject $12.1 million of the Company's regulatory tax assets to accelerated recovery in 1999.

The Rate Plan includes a provision that it may be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut. On October 1, 1999, the DPUC issued its decision establishing the Company's standard offer customer rates, commencing January 1, 2000, at a level 10% below 1996 rates, as directed by the Restructuring Act described in detail below. These standard offer customer rates are in effect for the period 2000-2001 and supercede the rate reductions for this period that were included in the Rate Plan. The decision also reduced the required amount of accelerated amortization in 2000 and 2001. Under this decision, all other components of the Rate Plan are expected to remain in effect through 2001. The Connecticut Office of Consumer Counsel, the statutory representative of consumer interests in public utility matters, is contesting the DPUC's calculation of the level of the Company's 1996 rates in an appeal taken to the Superior Court from the DPUC's decision.

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. As a result of the Act, the business of generating and selling electricity directly to consumers is opened to competition. These business activities are separated from the business of delivering electricity to consumers, also known as the transmission and distribution business. The business of delivering electricity remains with the incumbent franchised utility companies (including the Company), which continues to be regulated by the DPUC as Distribution Companies. Since mid-1999, Distribution Companies have been required to separate on consumers' bills the electricity generation services component from the charge for delivering the electricity and all other charges.

Major Influences on Financial Condition (continued)

A major component of the Restructuring Act is the collection, by Distribution Companies, of a "competitive transition assessment," a "systems benefits charge," an "energy conservation and load management program charge" and a "renewable energy investment charge." The competitive transition assessment represents costs that have been reasonably incurred by, or will be incurred by, Distribution Companies to meet their public service obligations as electric companies, and that will likely not otherwise be recoverable in a competitive generation and supply market. These costs include above-market long-term purchased power contract obligations, regulatory asset recovery and above-market investments in power plants (so-called stranded costs). The systems benefits charge represents public policy costs, such as generation decommissioning and displaced worker protection costs. Beginning in 2000, a Distribution Company must collect the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge from all Distribution Company customers.

The Restructuring Act requires that, in order for a Distribution Company to recover any stranded costs associated with its power plants, its fossil-fueled plants must be sold prior to 2000, with any net excess proceeds used to mitigate its recoverable stranded costs, and the Company must attempt to divest its ownership interests in its nuclear-fueled power plants prior to 2004.

On October 2, 1998, the Company agreed to sell both of its operating fossil-fueled generating stations, Bridgeport Harbor Station and New Haven Harbor Station, to Wisvest-Connecticut, LLC, a single-purpose subsidiary of Wisvest Corporation. Wisvest Corporation is a non-utility subsidiary of Wisconsin Energy Corporation, Milwaukee, Wisconsin. On April 16, 1999, the transaction closed and the Company received approximately $277.9 million from this sale. The Company realized a before-tax book gain of $86.5 million from the sale of these plant investments. However, under the Restructuring Act, this gain was offset by a writedown of the stranded costs eligible for collection by the Company under the Restructuring Act's competitive transition assessment, such that there was no net income effect of the sale. The Company used the net cash proceeds from the sale to reduce debt.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, and in other regulatory dockets, the Company stated that it plans to divest its nuclear generation ownership interests (17.5% of Seabrook Unit 1 in New Hampshire and 3.685% of Millstone Station Unit 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. The DPUC is currently considering the Company's plan for divesting its ownership interest in Millstone Unit 3 through an auction process to be conducted by a consultant to be selected by the DPUC. The divestiture process for Seabrook Unit 1 has not yet been determined. In anticipation of ultimate divestiture, the Company has satisfied the Restructuring Act's requirement that nuclear generating assets be separated from its transmission and distribution assets. This was accomplished by transferring the nuclear generating assets into a separate new division of the Company, using divisional financial statements and accounting to segregate all revenues, expenses, assets and liabilities associated with nuclear ownership interests. In a decision dated May 19, 1999, the DPUC approved the Company's proposal in this regard.

The Company's unbundling plan also proposes to separate its ongoing regulated transmission and distribution operations and functions, that is, the Distribution Company assets and operations, from all of its unregulated operations and activities. This would be achieved by undergoing a corporate restructuring into a holding company structure. In the holding company structure proposed, the Company will become a wholly-owned subsidiary of a holding company, and each share of the common stock of the Company will be converted into a share of common stock of the holding company. In connection with the formation of the holding company structure, all of the Company's interests in all of its operating unregulated subsidiaries will be transferred to the holding company and, to the extent new businesses are subsequently acquired or commenced, they will also be financed and owned by the holding company. An application for the DPUC's approval of this corporate restructuring was filed on November 13, 1998 and, in a decision dated May 19, 1999, the DPUC approved the proposed corporate restructuring. The Company has filed applications with the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission seeking approval of the proposed corporate restructuring, and a special meeting of the Company's shareowners will be held on March 17, 2000 to vote on approval of the restructuring.

On March 24, 1999, the Company applied to the DPUC for a calculation of the Company's stranded costs that will be recovered by it in the future through the competitive transition assessment under the Restructuring Act. In a decision dated August 4, 1999, the DPUC determined that the Company's stranded costs total $801.3 million, consisting of $160.4 million of above-market long-term purchased power contract obligations, $153.3 million of generation-related regulatory assets (net of related tax and accounting offsets), and $487.6 million of above-market investments in nuclear generating units (net of $26.4 million of gains from generation asset sales and other offsets related to generation assets). The DPUC decision provides that these stranded cost amounts are subject to true-ups, adjustments and potential additional future offsets, in accordance with the Restructuring Act. The Connecticut Office of Consumer Counsel, the statutory representative of consumer interests in public utility matters, is contesting the DPUC's calculation of the market value of the Company's generating assets in an appeal taken to the Superior Court from the DPUC's decision.

Under the Restructuring Act, retail customers representing a total of up to 35% of the Company's retail customer load became able to choose their power supply providers on and after January 1, 2000, and all of the Company's customers will be able to choose their power supply providers as of July 1, 2000. On and after January 1, 2000 and through December 31, 2003, the Company is required to offer fully-bundled "standard offer" electric service, under regulated rates, to all customers who do not choose an alternate power supply provider. The standard offer rates must include the fully-bundled price of generation, transmission and distribution services, the competitive transition assessment, the systems benefits charge and the conservation and renewable energy charges. The fully-bundled standard offer rates must also be at least 10% below the average fully-bundled prices in 1996.

In March of 1999, the DPUC commenced a proceeding to determine what the Company's standard offer rates should be under the above requirements of the Restructuring Act. In April, May and June of 1999, the Company filed descriptive material, data and supporting testimony with the DPUC setting forth the Company's overall approach for determining the components of its standard offer rates, and for continuation of the five-year Rate Plan ordered by the DPUC in its 1996 financial and operational review of the Company (see above) through the four-year standard offer period. On July 27, 1999, the Company and Enron Capital & Trade Resources Corp. (ECTR), an affiliate of Enron Corp., Houston, Texas (Enron) filed with the DPUC a joint stipulation and settlement proposal to resolve simultaneously all of the issues in the Company's standard offer rate proceeding. The proposal included an arrangement between the Company and ECTR whereby ECTR will supply all of the generation services needed by the Company to meet its standard offer obligations for the four-year standard offer period, and an assumption by ECTR of all of the Company's long-term purchased power agreement (PPA) obligations. The stipulation and settlement proposal also provided for the Company's standard offer rates at a fully-bundled level that complies with the 10% reduction required by the Restructuring Act, including the generation services component of these rates, the Company's stranded costs for purposes of future recovery, the competitive transition assessment, systems benefits charge, delivery (transmission and distribution) charges, and conservation, load management and renewable energy charges. The Company also requested that a purchased power adjustment clause authorized by the Restructuring Act be put in place to adjust standard offer rates for limited purposes, and that the Company's five-year Rate Plan, as modified and supplemented by the stipulation and settlement proposal, be continued during the four-year standard offer period. In its decision, dated October 1, 1999, on the Company's standard offer rates, the DPUC approved elements of the stipulation and settlement proposal, including the arrangements with ECTR, subject to specified changes, including

Major Influences on Financial Condition (continued)

changes in the level of the generation services component of customers' rates. On October 15, 1999, the Company filed its standard offer generation services component of rates in compliance with the DPUC's decision, and the Company and ECTR concurrently filed a revised stipulation and settlement proposal. These filings were approved by the DPUC on December 9, 1999 and, on December 28, 1999, the Company and Enron Power Marketing, Inc. (EPMI), another affiliate of Enron, entered into a Wholesale Power Supply Agreement, a PPA Entitlements Transfer Agreement and related agreements documenting the approved four-year standard offer power supply arrangement and the assumption of all of the Company's PPAs, effective January 1, 2000. From January 1, 2000 through June 30, 2000, EPMI will sell to the Company energy beyond that supplied by Wisvest as described above. The agreements also provide for the sale to EPMI of the Company's entitlements under all of its wholesale purchased power agreements (PPAs). However, unless or until a PPA is terminated or formally assigned to EPMI, the Company remains legally liable to pay the applicable power supplier all amounts due under the PPA. The agreements with EPMI also include a financially settled contract for differences related to certain call rights of EPMI and put rights of the Company with respect to the Company's entitlements in Seabrook Unit 1 and in Millstone Unit 3, and the Company's provision to EPMI of certain ancillary products and services associated with those nuclear entitlements, which provisions terminate at the earlier of December 31, 2003 or the date that the Company sells its nuclear interests. The agreements do not restrict the Company's right to sell to third parties the Company's ownership interests in those nuclear generation units or the generated energy actually attributable to its ownership interests.

Based on the decisions in the regulatory proceedings described above, the sale of the Company's fossil-generation assets in the second quarter of 1999, the planned divestiture of its nuclear generation ownership interests by the end of 2003, and in anticipation of the Restructuring Act becoming effective on January 1, 2000, the Company ceased applying SFAS No. 71 to the generation portion of its assets and operations as of December 31, 1999. Based on the favorable DPUC decisions that allow full recovery, through the Company's rates, of all historically incurred stranded costs, the Company did not record any write-offs in connection with this event.

Liquidity and Capital Resources

The Company's capital requirements are presently projected as follows:

(In Millions of Dollars)	2000	2001	2002	2003	2004
Cash on Hand – Beginning of Year (1)	$39.1	$ –	$ –	$ –	$ –
Internally Generated Funds less Dividends (2)	76.5	87.8	88.8	98.9	76.7
Subtotal	115.6	87.8	88.8	98.9	76.7
Less:					
Utility Capital Expenditures (2)	58.1	36.1	18.9	21.8	30.8
Non-Regulated Business Capital Expenditures	4.3	5.4	3.9	4.0	4.2
Cash Available to pay Debt Maturities and Redemptions	53.2	46.3	66.0	73.1	41.7
Less:					
Maturities and Mandatory Redemptions	–	–	100.0	100.0	–
Optional Redemptions	75.0	–	–	–	–
Repayment of Short-Term Borrowings	17.0	–	–	–	–
External Financing Requirements (Surplus) (2)	$38.8	$(46.3)	$34.0	$26.9	$(41.7)

(1) Excludes $2.3 million Seabrook Unit 1 operating deposit and restricted cash of American Payment Systems, Inc. of $26.9 million.

(2) Internally Generated Funds less Dividends, Capital Expenditures and External Financing Requirements are estimates based on current earnings and cash flow projections. All of these estimates are subject to change due to future events and conditions that may be substantially different from those used in developing the projections.

All of the Company's capital requirements that exceed available cash will have to be provided by external financing. Although the Company has no commitment to provide such financing from any source of funds, other than a $60 million revolving credit agreement with a group of banks, described below, the Company expects to be able to satisfy its external financing needs by issuing additional short-term and long-term debt. The continued availability of these methods of financing will be dependent on many factors, including conditions in the securities markets, economic conditions, and the level of the Company's income and cash flow.

On January 16, 1999, the Company repaid $66.2 million principal amount of 6.20% Notes at maturity.

On February 1, 1999, the Company converted $7.5 million principal amount of Connecticut Development Authority Bonds from a weekly reset mode to a five-year multiannual mode. The interest rate on the Bonds for the five-year period beginning February 1, 1999 is 4.35% and interest is payable semi-annually on August 1 and February 1. In addition, on February 1, 1999, the Company converted $98.5 million principal amount Business Finance Authority of the State of New Hampshire Bonds from a weekly reset mode to a multiannual mode. The interest rate on $27.5 million principal amount of the Bonds is 4.35% for a three-year period beginning February 1, 1999. The interest rate on $71 million principal amount of the Bonds is 4.55% for a five-year period. Interest on the Bonds is payable semi-annually on August 1 and February 1.

On March 8, 1999, the Company prepaid and terminated $20 million of the remaining $70 million outstanding debt under its $150 million Term Loan Agreement dated August 29, 1995. On April 16, 1999, the Company prepaid and terminated the entire remaining $50 million outstanding debt under said $150 million Term Loan Agreement, and the entire $75 million outstanding debt under its Term Loan Agreement dated October 25, 1996.

On April 8, 1999, the Company called for redemption all 10,370 shares of its outstanding $100 par value 4.35% Preferred Stock, Series A, all 17,158 shares of its outstanding $100 par value 4.72% Preferred Stock, Series B, all 12,745 shares of its outstanding $100 par value 4.64% Preferred Stock, Series C and all 2,712 shares of its outstanding $100 par value 5 5/8% Preferred Stock, Series D. The Company paid a redemption premium of $53,355 in effecting these redemptions, which were completed on May 14, 1999.

On December 16, 1999, the Company borrowed $25 million from the Business Finance Authority of the State of New Hampshire (BFA), representing the proceeds from the issuance by the BFA of $25 million principal amount of tax-exempt Pollution Control Refunding Revenue Bonds (PCRRBs). The Company is obligated, under its borrowing agreement with the BFA, to pay to a trustee for the PCRRBs' bondholders such amounts as will pay, when due, the principal of and the premium, if any, and interest on the PCRRBs. The PCRRBs will mature in 2029, and their interest rate is fixed at 5.4% for the three-year period ending December 1, 2002. At December 31, 1999, these proceeds were held by a trustee and were recognized as cash and long-term debt on the Consolidated Balance Sheet. The Company has used the proceeds of this $25 million borrowing to cause the redemption and repayment of $25 million of 8.0%, 1989 Series A, Pollution Control Revenue Bonds, an outstanding series of tax-exempt bonds on which the Company also had a payment obligation to a trustee for the bondholders. Expenses associated with this transaction, including redemption premiums totaling $750,000 and other expenses of approximately $417,000, were paid by the Company.

The Company has a revolving credit agreement with a group of banks, which currently extends to December 7, 2000. The borrowing limit of this facility is $60 million. The facility permits the Company to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by the Eurodollar interbank market in London. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1999, the Company had $17 million in short-term borrowings outstanding under this facility.

Liquidity and Capital Resources (continued)

The Company's long-term debt instruments do not limit the amount of short-term debt that the Company may issue. The Company's revolving credit agreement described above requires it to maintain an available earnings/interest charges ratio of not less than 1.5:1.0 for each 12-month period ending on the last day of each calendar quarter. For the 12-month period ended December 31, 1999, this coverage ratio was 4.7:1.0.

The provisions of the financing documents under which the Company leases a portion of its entitlement in Seabrook Unit 1 from an owner trust established for the benefit of an institutional investor presently require the Company to maintain its consolidated annual after-tax cash earnings available for the payment of interest at a level that is at least one and one-half times the aggregate interest charges paid on all indebtedness outstanding during the year. On the basis of the formula contained in the Seabrook Unit 1 lease financing documents, the coverage for the year ended December 31, 1999 was 4.7.

The Company is obligated to furnish a guarantee for its participating share of the debt financing for the Hydro-Quebec Phase II transmission intertie facility linking New England and Quebec, Canada. As of December 31, 1999, the Company's guarantee liability for this debt was approximately $6.2 million.

At December 31, 1999, the Company had $68.3 million of cash and temporary cash investments, a decrease of $56.2 million from the corresponding balance at December 31, 1998. The components of this decrease, which are detailed in the Consolidated Statement of Cash Flows, are summarized as follows:

(In Millions of Dollars)

Balance, December 31, 1998	$ 124.5
Net cash provided by operating activities	98.5
Net cash provided by (used in) financing activities:	
– Financing activities, excluding dividend payments	(266.9)
– Dividend payments	(40.6)
Investment in debt securities	5.5
Net cash provided from sale of generation assets	270.6
Cash invested in unregulated businesses	(88.5)
Cash invested in plant, including nuclear fuel	(34.8)
Net Change in Cash	(56.2)
Balance, December 31, 1999	$ 68.3

Subsidiary Operations

The Company has one wholly-owned subsidiary, United Resources, Inc. (URI), that serves as the parent corporation for several unregulated businesses, each of which is incorporated separately to participate in business ventures that will complement the Company's regulated electric utility business and provide long-term rewards to the Company 's shareowners.

URI has four wholly-owned subsidiaries. American Payment Systems, Inc. manages a national network of agents for the processing of bill payments made by customers of the Company and other companies. Another subsidiary of URI, United Capital Investments, Inc., and its subsidiaries, participate in business ventures that complement the Company's business. A third URI subsidiary, Precision Power, Inc. and its subsidiaries, provide specialty electrical, telecommunications and mechanical contracting and power-related services to the owners of commercial buildings and industrial and institutional facilities. URI's fourth subsidiary, United Bridgeport Energy, Inc., is a participant in a merchant wholesale electric generating facility located in Bridgeport, Connecticut.

The after-tax impact of the subsidiaries on the consolidated financial statements of the Company is as follows:

	Net Loss (000's)	Loss Per Share (Basic & Diluted)	Assets at Dec. 31 (000's)
1999	$2,256	$0.16	$194,642
1998	1,111	0.08	83,306
1997	2,185	0.16	69,338

In 1997, the Company made provisions for losses of $1.6 million (after-tax) associated with collection agent errors and defaults and miscellaneous other items at its American Payment Systems, Inc. subsidiary.

New Accounting Standards

See the discussion included in Notes to Consolidated Financial Statements – Note (A), Statement of Accounting Policies.

Results of Operations

1999 vs. 1998 Earnings for the twelve months of 1999 were $52.1 million, or $3.71 per share (on both a basic and diluted basis), up $7.2 million, or $.51 per share, from the twelve months of 1998. Excluding one-time items recorded during both periods, earnings from operations for 1999 were $51.5 million, or $3.67 per share (on both a basic and diluted basis), up $3.7 million, or $.26 per share, from the twelve months of 1998.

Earnings from operations for 1999 before earnings "sharing" were $5.09 per share, $1.44 per share or 39% higher than 1998. "Sharing" reduced the 1999 earnings from operations to $3.67 per share.

The one-time items recorded in 1999 and 1998 were:

		EPS
1999 Quarter 1	Purchased power expense refund	$ .12
	Sharing due to refund	$(.08)
1998 Quarter 3	Refund of prior period transmission charges, with interest	$ .14
	Sharing due to one-time items recorded through 3rd quarter	$(.05)
1998 Quarter 4	Property tax settlement with the City of New Haven	$(.59)
	Reversal of sharing imputed to property tax settlement	$ .29

UTILITY EARNINGS FROM OPERATIONS Overall, retail sales margin decreased by $13.2 million in 1999 compared to 1998, and retail sales margin from operations decreased by $9.4 million. Retail revenues from operations increased by $11.9 million as electric revenues increased for the reasons detailed below. Retail revenues decreased by $3.9 million because of "sharing" required under the current regulatory structure as applied to the one-time items recorded in both periods. Retail fuel and energy expense from operations increased by $20.7 million, primarily from higher purchased power prices as a result of the Company's transition from a

Results of Operations (continued)

producer to a purchaser of its customers' energy requirements, and the need to purchase additional energy to replace power lost from nuclear plant refueling outages. The principal components of the retail sales margin change for 1999, compared to 1998, include:

(In Millions of Dollars)	From Operations	From One-time	Total
Retail Sales Margin:			
Revenue from:			
Sharing: for 1999 (see Note A)	(14.4)	(3.9)	(18.3)
Estimate of "real" retail sales growth, up 3.2%	20.2	0.0	20.2
Estimate of weather effect on retail sales, up 1.1%	7.1	0.0	7.1
Sales decrease from Yale University cogeneration, (0.6)%	(3.6)	0.0	(3.6)
Price mix of sales and other	2.6	0.0	2.6
TOTAL RETAIL REVENUE	11.9	(3.9)	8.0
REVENUE BASED TAXES	(0.6)	0.1	(0.5)
Fuel and energy, margin effect:			
Sales increase	(4.7)	0.0	(4.7)
Nuclear fuel prices and outage replacement power costs	(0.5)	0.0	(0.5)
Purchased energy prices (see Note B)	(15.5)	0.0	(15.5)
TOTAL RETAIL FUEL AND ENERGY	(20.7)	0.0	(20.7)
TOTAL RETAIL SALES MARGIN	(9.4)	(3.8)	(13.2)

A The Company's preliminary return on regulated utility common stock equity for the twelve months of 1999 exceeded the 11.5% "sharing" trigger by a total amount of about $53 million of pre-tax income. As a result, and excluding "sharing" associated with one-time items, a book revenue "sharing" reduction from operations of $17.4 million, including a gross earnings tax component, was recorded in 1999, approximately $14.4 million more than the $3.0 million book revenue "sharing" reduction imputed from operations in 1998. All 1998 sharing from operations was offset by the impact of sharing associated with a one-time item recorded in December of 1998.

B On April 16, 1999, the Company completed the sale of its operating fossil-fueled generating plants and existing wholesale sales contracts that was required by Connecticut's electric utility industry restructuring legislation. As a result, the "geography" of the Company's costs on the income statement and, hence, the year-over-year variances, changed significantly beginning in the second quarter. This particularly relates to wholesale revenue, retail purchased energy and fossil fuel expenses, operation and maintenance expense, depreciation, interest charges and property taxes. For example, the increased purchased energy costs included in the table above are more than offset by some of the decline in miscellaneous operation and maintenance expense, due principally to the sale of generating plants, shown in the table below, and to decreases in depreciation and property taxes.

Net wholesale margin (wholesale revenue less wholesale expense) decreased by $10.4 million in 1999 compared to 1998 from lower wholesale sales. Other operating revenues, which include NEPOOL related transmission revenues, increased by $6.4 million. NEPOOL transmission revenues are recoveries, for the most part, of NEPOOL transmission expense and simply reflect new accounting requirements implemented by the Federal

Energy Regulatory Commission.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $5.7 million in 1999 compared to 1998. The principal components of these expense changes include:

(In Millions of Dollars)

Capacity expense:	
Connecticut Yankee	(2.4)
Cogeneration and other purchases (see Note A)	1.8
TOTAL CAPACITY EXPENSE	(0.6)
Other O&M expense:	
Seabrook Unit 1 (refueling outage costs and accruals)	4.1
Millstone Unit 3 (refueling outage costs and accruals)	1.1
Other expenses at nuclear units	(0.8)
Fossil generation unit operating and maintenance costs	(23.1)
NEPOOL transmission expense	3.4
Site remediation costs (see Note B)	7.8
Other miscellaneous, including impact of generation asset sale	2.4
TOTAL O&M EXPENSE	(5.1)

Note A: A cogeneration facility was out of service for about a month in the first quarter of 1998 but has operated normally in 1999.

Note B: These costs were incurred to repair a bulkhead at English Station and for remediation of environmental conditions at another site. No further material expenses are currently anticipated for remediation of these sites.

Depreciation expense decreased by $12.4 million in 1999 compared to 1998, due primarily to the generation asset sale.

On December 31, 1996, the Connecticut Department of Public Utility Control issued an order that implemented a five-year Rate Plan to reduce the Company's retail prices and accelerate the recovery of certain "regulatory assets." According to the Rate Plan, under which the Company is currently operating, "accelerated" amortization of past utility investments is scheduled for every year that the Rate Plan is in effect, contingent upon the Company earning a 10.5% return on utility common stock equity. All of the scheduled accelerated amortization for 1998, amounting to $13.1 million before-tax ($8.5 million after-tax), was recorded against earnings from operations in 1998. The Company recorded all of the scheduled accelerated amortization for 1999 by amortizing regulatory income tax assets, totaling $12.1 million after-tax ($20 million pre-tax equivalent).

The Company can also incur additional accelerated amortization expense as a result of the "sharing" mechanism in the Rate Plan, if the Company achieves a return on utility common stock equity above 11.5%, which the Company did achieve during the third quarter of 1999. One-time items recorded against the return on utility common stock equity, before the Company achieves the 11.5%, are recorded with an appropriate "sharing" effect if the Company projects, at that time, that there will be total "sharing" for the year adequate to cover the "sharing" for the one-time item. Such "sharing" amortization was recorded in the first quarter of 1999, in the amount of $1.0 million before-tax ($0.6 million after-tax), as a result of the one-time gain recorded in that quarter. "Sharing" amortization from operations of $10.0 million after-tax ($16.7 million before-tax) was recorded in 1999. "Sharing" amortizations recorded and imputed in the first nine months of 1998 were: $0.5 million before-tax ($0.3 million after-tax) as a result of a one-time item, and $2.1 million before-tax ($1.2 million after-tax) from operations. "Sharing" amortization recorded against earnings from operations in the fourth quarter of 1998 was imputed to be $0.6 million before-tax ($0.3 million after-tax). All of those 1998 "sharing" amortizations were reversed in the fourth quarter of 1998 as a result of the impact of a one-time charge recorded in that quarter.

Results of Operations (continued)

Interest charges continued on a downward trend, decreasing by $12.8 million for the regulated business in 1999 compared to 1998, partly offset by an increase of $3.5 million in interest charges for non-regulated subsidiaries. Most of the reduction in utility interest charges occurred after the generation asset sale, which was completed on April 16, 1999. On that date, the Company used proceeds received from the sale of plant to pay off $205 million of debt.

NON-REGULATED BUSINESS EARNINGS FROM OPERATIONS Overall, non-regulated businesses, after parent-allocated interest but before income taxes, lost approximately $3.8 million in 1999 compared to losses of about $1.8 million in 1998. American Payment Systems, Inc. (APS) earned approximately $2.6 million (before-tax) in 1999, reflecting an increase of $1.0 million over 1998. Precision Power, Inc. (PPI) lost approximately $5.1 million (before-tax) in 1999, compared to a loss of approximately $2.4 million in 1998, reflecting increased infrastructure costs and lower than anticipated contract margins.

On May 11, 1999, the Company's non-regulated subsidiary, United Bridgeport Energy, Inc. (UBE), increased its 4% passive investment in Bridgeport Energy LLC (BE) to 33 1/3%. The second phase of BE's merchant wholesale electric generating project went into commercial operation in July 1999, adding 180 megawatts of generation capacity for a total of 520 megawatts. UBE lost approximately $0.1 million (before-tax) in 1999, as a result of the second quarter shutdown of the first phase generator to allow for construction of the second phase, and additional unscheduled outages and higher gas prices in the fourth quarter of 1999. Other non-regulated subsidiary operations lost approximately $1.2 million in 1999, compared to a similar loss in 1998.

Non-regulated business before-tax income is reported as part of "Other net" income; parent interest charges allocated to the non-regulated businesses are reported as part of "Interest charges"; and related income tax expense is reported as part of "Non-operating income taxes."

(In Millions of Dollars)	12 mos. ended Dec. 99	12 mos. 99 vs. 98
Summary of Non-regulated Business Unit Pre-tax Income:		
American Payment Systems, Inc.	2.6	1.0
Precision Power, Inc.	(5.1)	(2.7)
United Bridgeport Energy, Inc.	(0.1)	(0.1)
United Resources, Inc. Capital Projects	(1.2)	–
TOTAL NON-REGULATED BUSINESSES	(3.8)	(1.8)

1998 vs. 1997 Earnings for the twelve months of 1998 were $44.9 million, or $3.20 per share (both basic and diluted), up $1.6 million, or $.11 per share, from the twelve months of 1997, diluted. Excluding one-time items, accelerated amortization due to one-time items and associated regulated "sharing" effects, 1998 earnings from operations were $47.8 million, or $3.41 per share, up $.48 per share from 1997. The one-time items and their earnings per share impacts recorded in these periods are shown at "One-time items recorded in 1997 and 1998" on page 29.

Retail operating revenues increased by about $9.3 million in the twelve months of 1998 compared to 1997. Retail fuel and energy expense increased by $7.2 million and there was an increase of $0.4 million in revenue-based taxes. Overall, retail sales margin (revenue less fuel expense and revenue-based taxes) from operations increased by $1.7 million. The principal components of the retail sales margin change, year over year, include:

(In Millions of Dollars)	
Revenue from:	
DPUC rate order, excluding "sharing"	(1.3)
Other price changes	(0.3)
Estimate of "real" retail sales growth, up 1.3%	12.1
Estimate of weather effect on retail sales, up 0.2 %	1.8
Sales decrease from Yale University cogeneration, (0.9) %	(3.0)
TOTAL REVENUE IMPACT	9.3
Fuel and energy, margin effect:	
Sales increase	(2.7)
Increased nuclear availability	0.4
Unscheduled outage at Bridgeport Unit 3 (see Note A)	(2.5)
Fossil price and other	(2.4)
TOTAL FUEL AND ENERGY IMPACT	(7.2)

Note A: Saltwater contamination caused a shutdown of the Bridgeport Harbor Unit 3 generating unit on May 22, 1998. The unit returned to full service on August 23, 1998.

Net wholesale margin (wholesale revenue less wholesale energy expense) increased slightly in the twelve months of 1998 compared to the twelve months of 1997. Other operating revenues, which include NEPOOL related transmission revenues, increased by $5.8 million.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $15.0 million in the twelve months of 1998 compared to the twelve months of 1997. The principal components of these expense changes, year over year, include:

(In Millions of Dollars)	
Capacity expense:	
Connecticut Yankee preparing for decommissioning	(4.2)
Cogeneration and other purchases	(1.3)
Other O&M expense:	
Seabrook	(4.6)
Millstone Unit 3	(4.0)
Fossil generation unit overhauls and outages	7.5
Pension investment performance and assumptions	(3.0)
Personnel reductions	(6.0)
NEPOOL transmission expense	3.1
Other	(2.5)

Depreciation expense, excluding accelerated amortization, increased by $1.5 million in the twelve months of 1998 compared to 1997. According to the Company's current regulatory Rate Plan, "accelerated" amortization of past utility investments is scheduled for every year that the Rate Plan is in effect, contingent upon the Company earning a 10.5% return on utility common stock equity. All of the accelerated amortization in 1997 was recorded ratably throughout the year as a charge to depreciation expense. All of the accelerated amortization for 1998, $13.1 million, was recorded against earnings from operations. In addition, as part of the "sharing"

Results of Operations (continued)

mechanism, the Company would have accrued an additional amortization of about $2.6 million ($1.7 million after-tax) in 1998 against utility earnings from operations. Because of the one-time items in 1998, no "sharing" was actually recorded. The one-time charge for property tax expense incurred in the fourth quarter was a utility expense and negated the "sharing" that would have occurred from operations.

Other net income from operations decreased by about $1.9 million in the twelve months of 1998 compared to 1997. The Company's largest unregulated subsidiary, American Payment Systems, Inc. (APS), earned about $1.6 million (before-tax) in 1998 compared to a $2.7 million loss in 1997. This was more than offset by greater losses, compared to 1997, in the Company's other unregulated subsidiaries: $1.2 million (before-tax) at Precision Power, Inc. from the write-off of previously deferred costs and a review of reserves, and $1.2 million (before-tax) from start-up costs in other unregulated activities. By DPUC order, since consolidation at the unregulated subsidiary level produced no net taxable income in either year, the tax benefits associated with the losses, about $0.8 million in 1998 and $0.4 million in 1997, were treated as benefits to utility income for the purposes of calculating return on utility common equity and "sharing." Other net income also decreased due to the absence of other non-utility income accruals of about $1 million made in 1997 that reversed a provision for 1997 Millstone 3 expense made in 1996 and charged to operating expenses in 1997, cancelled project costs of about $0.8 million for merger and acquisition advisor fees and analysis and lower income from non-operating utility investments.

Interest charges, excluding allowance for borrowed funds used during construction, continued on their downward trend, decreasing by $10.4 million in the twelve months of 1998 compared to 1997, as a result of the Company's refinancing program and strong cash flow.

Overview of "Sharing" and the Impact on Earnings

As previously indicated, the Company's regulatory Rate Plan requires a "sharing" of regulated utility income that produces a return on utility equity exceeding 11.5%. The measurement of this utility income and resulting return calculation includes the effects of any utility one-time items. Under the Rate Plan, one-third of the income above the 11.5% return would be applied to customer bill reductions, one-third would be applied to additional amortization of regulatory assets, and one-third would be retained by shareowners.

Earnings from operations, which excludes the impact of one-time items, should reflect an appropriate imputed amount of "sharing" to reflect accurately what the earnings would have been had neither the one-time items, nor their impact on "sharing," occurred. The Company estimates that the "sharing" that would have occurred had there been no one-time items in 1998 would have been: a revenue reduction of about $3.0 million or $.12 per share, increased amortization of about $1.7 million (after-tax) or $.12 per share, and retention by the Company of $1.7 million of income (after-tax) or $.12 per share. To summarize for 1998:

	From Operations and "Sharing"	One-time Items and "Sharing" Reversals	Total
1998 Earnings per share (EPS)			
Utility earnings before "sharing"	$3.73	$(.45)	$3.28
Less: Utility earnings to be "shared"	(.36)	.36	–
Utility EPS at 11.5% utility return	$3.37	$(.09)	$3.28
Plus: 1/3 Retained "Sharing" benefit	.12	(.12)	–
Net Utility EPS	3.49	(.21)	3.28
Unregulated Subsidiaries	(.08)	–	(.08)
Total 1998 EPS	$3.41	$(.21)	$3.20
Earnings reported through 3rd quarter	3.02	(.12)	2.90
Imputed 4th quarter earnings	$.39	$(.09)	$ .30

One-time items recorded in 1997 and 1998

	One-time Items	EPS
1997	Cumulative deferred operating income tax benefits associated with future Decommissioning of fossil fuel generating plants (see explanation below)	$ .48
	Accelerated amortization associated with one-time item	$(.30)
	Gain from subleasing office space	$ .05
	Pension benefit adjustments associated with 1996 VERP and VSP	$ .11
	Contract termination charge	$(.18)
1998	Refund of prior period transmission charges, with interest	$ .14
	"Sharing" due to one-time items recorded through third quarter	$(.05)
	Property tax settlement with the City of New Haven, CT	$(.59)
	Reversal of "sharing" imputed to property tax settlement	$ .29

In accordance with a DPUC decision issued December 31, 1996 and effective for years 1997-2001, related to a financial and operational review of the Company (the Rate Plan), the Company was directed to explore and implement ways to reduce its potentially stranded costs. In addition, the decision required the Company to record a specified amount of accelerated amortization of conservation and load management costs during 1997 ($6.4 million before-tax, $4.1 million after-tax) as a stranded costs mitigation effort if the Company's return on its utility common stock equity exceeded 10.5% for that year. Based on these requirements, the Company recorded an operating income tax expense reduction of $6.7 million, or $.48 per share, in the first quarter of 1997, which made provision for the cumulative deferred tax benefit associated with the estimated future decommissioning costs of fossil fuel generating plants for which the Company had made provision in prior years without accruing the tax benefit. This tax benefit, originally recorded in the second quarter of 1997, has been restated to the first quarter of 1997 following consultations with the staff of the Securities and Exchange Commission and the Company's independent accountants to coincide with the effective date of the Rate Plan. As a result of recording the tax benefit, the Company exceeded the 10.5% utility common stock equity return and therefore was able to record the specified amount of accelerated amortization required in the Rate Plan for 1997. The accelerated amortization, which was originally recorded in the second quarter of 1997, has been restated and is now recorded ratably throughout 1997 as a charge to depreciation expense on the consolidated income statement. The after-tax amount of accelerated amortization was less than the cumulative deferred tax benefit because the after-tax amount of additional amortization was specified in the Rate Plan while the deferred tax benefit was calculated based upon the cumulative amount of estimated future decommissioning costs that had been recovered through rates at that time.

During prior years, the Company had recognized, on a net basis, the deferred tax assets and offsetting regulatory tax liability related to these tax benefits associated with the future decommissioning of its fossil generating plants on its consolidated balance sheet in accordance with Statement of Financial Accounting Standards No. 109. The Company had recognized this regulatory tax liability through the systematic recovery of before-tax future decommissioning costs for its fossil generating units in its rates over the useful lives of these units.

Additional 1997 one-time items included: a $.05 per share gain related to subleasing office space; a "curtailment" gain of $2.5 million ($1.5 million after-tax), or $.11 per share, related to forgone pension benefits associated with the approximate 230 employees who left the Company as a result of 1996 voluntary retirement and separation programs; and a charge of $4.3 million ($2.5 million after-tax), or $.18 per share, for early termination of a contract with consultants that assisted the Company with its restructuring efforts, after the Company determined that the early termination option was more economic than the multi-year performance-based payout option. All of these one-time items were recorded as "Operating Expense – Operations – other."

One-time items recorded in 1997 and 1998 (continued)

As reported in its Quarterly Report on Form 10-Q for the period ending March 31, 1998, filed with the Securities and Exchange Commission, the Company had been investigating potential errors in the accounting procedure of APS. As a result of the investigation, the Company determined that APS should create additional reserves for shortfalls in agent collections and other potentially uncollectible receivables of $4.9 million. Of the total of $4.9 million, $2.8 million and $2.1 million were restated to 1997 and 1996, respectively, to provide for the reserves in the relevant periods. See PART II, Item 8, "Financial Statements and Supplementary Data – Notes to Consolidated Financial Statements – Note (Q), Restatement of Financial Results."

The principal business of APS is to operate a network of field agents for the purpose of accepting cash and check payments of clients' bills and forwarding those payments, through APS accounts, to the client. APS experienced rapid growth in 1996 and 1997. The number of agents in the APS network increased from 2,537 in 1995 to 4,904 in 1997; and the dollar volume of payment transactions increased from $2.3 billion on 17.2 million transactions in 1995 to $7.5 billion on 73.2 million transactions in 1997.

At year-end 1996, APS created a reserve to provide for losses associated with agent collections and uncollectible check deposits totaling $4.4 million before-tax. The Company has restated its 1996 earnings to move $0.7 million of this loss to 1995. See PART II, Item 8, "Financial Statements and Supplementary Data – Notes to Consolidated Financial Statements – Note (Q), Restatement of Financial Results." These losses stemmed from inadequate "back-office" banking systems and controls that failed to detect a significant amount of deposit shortfalls from agents and failed to identify a substantial number of uncollectible check deposits that were reimbursable from the clients serviced. Specifically, APS agent bank accounts were not fully reconciled at the time the APS balance sheet items were prepared to allow for the identification, measurement and enforcement of material claims for recovery from APS agents for defalcated amounts or from APS customers for checks returned by banks due to insufficient funds.

In 1997, under new management with added banking expertise, APS began implementing new systems and controls to manage the agent collection/deposit process. These changes included the increased use of daily cash reporting and account reconciliation on high volume agents, extensive reconciliation procedures, and agent monitors that interact daily with agents to investigate discrepancies in deposits. These new procedures were fully implemented by the 4th quarter of 1997.

In March of 1998, APS contracted for an insurance policy with an A+ rated carrier to protect against future losses from robberies, missing deposits, and agent fraud. The effect of the policy is to "cap" the cost of such losses at $200,000 per event per agent. The level of detected agent fraud in 1998 was well below that level, averaging $23,000 per month in total, or .004% of the monthly transaction dollar volume.

Also in 1998, APS implemented new procedures to correct difficulties in tracking agent deposits in bank merger or acquisition situations. During this process, it was discovered that certain large agent depository bank accounts were not reconciled appropriately and that the amount of APS working capital invested in the agent depository accounts to cover timing delays for cash transfers was over-estimated and the amount due to utilities underestimated. These cash flow discrepancies were masked by the rapid growth of cash deposits from the expansion in the agent network and the failure to properly take into account the cash effects of uncleared bank transfers from agent depository accounts to utilities. APS accounting procedures, which failed to detect the cash flow discrepancies, have been rectified.

At December 31, 1998, the consolidated balance sheet reflected $54.5 million of accounts payable owed to APS customers. This payable was relieved by $23.1 million of APS restricted cash, representing collections by APS agents prior to transmittal to the respective APS customers and $31.4 million of accounts receivable representing collections by APS agents that had not yet been deposited into APS bank accounts. Of the accounts payable and accounts receivable amounts, $4.7 million had originally been recorded on the consolidated balance sheet as of December 31, 1998.

The following table summarizes the effect of the restatements described above to the provision for APS losses, restricted cash, other accounts receivable, and accounts payable – APS customers:

(In Thousands) For the Year Ended December 31	1998	1997	1996	1995
Provision for APS losses (before-tax), as originally reported	$4,900	$ –	$ 4,471	$ –
Effect of restatement, described above	(4,900)	2,825	1,279	796
Provision for APS losses (before-tax), as restated	$ –	$ 2,825	$ 5,750	$ 796

(In Thousands) As of December 31,	1998	1997	1996
Restricted cash, as originally reported	$ –	$ –	$ –
Effect of restatement, described above	23,056	21,063	16,681
Restricted cash, as restated	$23,056	$21,063	$16,681
Other accounts receivable, as originally reported (1)	$37,472	$27,914	$38,367
Effect of restatement, described above			
Additional accounts receivable for APS agents	26,768	23,284	19,903
Additional APS agent collection reserves	–	(4,900)	(2,075)
Other accounts receivable, as restated	$64,240	$46,298	$56,195

(In Thousands) As of December 31,	1998	1997	1996
Accounts payable-APS customers, as originally reported	$ –	$ –	$ –
Accounts payable-APS customers reclassed from accounts payable	4,691	6,147	7,588
Effect of restatement, described above			
Restricted cash	23,056	21,063	16,681
Additional amounts owed to APS customers	26,768	23,284	19,903
Accounts payable-APS customers, as restated	$54,515	$50,494	$44,172

(1) Includes accounts receivable from APS agents originally included in other accounts receivable of $4,691,000, $6,147,000 and $7,588,000 as of December 31, 1998, 1997 and 1996, respectively.

The one-time gain recorded in the third quarter of 1998 was to record a refund of prior period transmission charges. It amounted to $3.4 million or $.14 per share, but was recorded as two separate items; $1.8 million, or a gain of $.07 per share, as a credit to operation expense and $1.6 million, or $.07 per share, of interest income recorded as Other Income and (Deductions), Other-net. At the time this one-time item was recorded, in the third quarter of 1998, the Company estimated that it would be in the Rate Plan "sharing" range of earnings for the year of 1998 in total, and recorded, therefore, a "sharing" revenue reduction and increased amortization expense to reflect that estimate. The "sharing" related to the utility portion of this one-time item, the operation expense credit, was a charge of $.05 per share. The net result of the one-time gain for the period was, therefore, $.09 per share. The one-time charge recorded in the fourth quarter of 1998 as property tax expense of $14 million, or $.59 per share, reflected the DPUC's rejection of the Company's proposed accounting treatment of a property tax settlement between the Company and the City of New Haven. Upon that rejection, the Company was required to write-off immediately the full effect of that settlement. As a result of this one-time charge, the Company's final 1998 earnings results eliminated the requirement to record any Rate Plan "sharing" in 1998. The one-time charge eliminated "sharing" revenue reductions and increased amortization expense amounting to $.29 per share. The net result of the one-time charge for the period was, therefore, $.30 per share.

Looking Forward

(The following discussion contains forward-looking statements, which are subject to uncertainties that could cause actual results to differ materially from those currently expected. Readers are cautioned that the Company regards specific numbers as only the "most likely" to occur within a range of possible values.)

FIVE-YEAR RATE PLAN On December 31, 1996, the Connecticut Department of Public Utility Control (DPUC) issued an order (the Order) that implemented a five-year regulatory framework to reduce the Company's retail prices and accelerate the recovery of certain "regulatory assets," beginning with deferred conservation costs. The Company has operated under the terms of this Order since January 1, 1997. The Order's schedule of price reductions and accelerated amortizations was based on a DPUC pro-forma financial analysis that anticipated the Company would be able to implement such changes and earn an allowed annual return on common stock equity invested in utility assets of 11.5% over the period 1997 through 2001. The Order established a set formula to share (see "Sharing Implementation" below) any utility income that would produce a return above the 11.5% level: one-third to be applied to customer price reductions, one-third to be applied to additional amortization of regulatory assets, and one-third to be retained by shareowners. Utility income is inclusive of earnings from operations and one-time items. See "Major Influences on Financial Condition" for a more extensive description of the five-year Rate Plan.

SHARING IMPLEMENTATION Based on the traditional quarterly earnings pattern, the Company realizes about one-half of its pre-sharing utility earnings in the third quarter of each year. The Company will not likely ever exceed the sharing level of utility earnings before the third quarter of any year that "sharing" is in effect. Assuming the sharing level of utility earnings is exceeded in the third quarter of a particular year, then all positive utility earnings recorded in the fourth quarter of that year will be subject to "sharing."

A LOOK AT 2000; CONTINUED GROWTH OF NON-REGULATED BUSINESS VALUE On January 1, 2000, the Company completed the restructuring process required by the Connecticut electric utility industry restructuring legislation in 1998 and its regulated business became an electricity delivery business. All customers are now seeing at least a 10% reduction in their electric rates from 1996 levels.

The framework of the current Rate Plan, including the "sharing" mechanism, is expected to continue through 2001. Regulatory decisions during 1999 did not alter the Company's allowed return of 11.5% on utility equity, and did not impinge upon the Company's ability to achieve that return.

If the Company were to earn 11.5% on equity in the regulated business, that level of earnings should generate $3.25-$3.35 per share. In addition, operation of the Company's nuclear entitlements should contribute to earnings until such time as the units are sold. The Company expects that utility income for common stock above 11.5% return will be greatly reduced from 1999 levels, due to mandates in the restructuring legislation; and the Company expects that the shareowners' portion of shared utility income will contribute no more than $.10-$.15 per share. Under these assumptions, customers also will see reduced benefits.

Non-regulated businesses are expected to make significant contributions to earnings in 2000. Both American Payment Systems and United Bridgeport Energy should each contribute $.10-$.15 per share in 2000. Precision Power and the balance of United Resources, Inc. are expected to lose up to $.05 per share. As a result of management's continued confidence in the potential of the non-regulated businesses, the Company is evaluating further investments in this area. However, additional losses could be incurred due to new growth initiatives if the potential for future benefits warrant such losses.

Total earnings for 2000, including the regulated business with sharing and the non-regulated business units, are now estimated to be in the range of $3.60 to $3.80 per share. This estimate is contingent upon normal weather and normal operation of the nuclear units.

Report of Independent Accountants

To the Board of Directors and the Shareholders of The United Illuminating Company

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, of changes in shareholders' equity and of cash flows present fairly, in all material respects, the financial position of The United Illuminating Company and its subsidiaries (the "Company") at December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States. 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 of these statements in accordance with auditing standards generally accepted in the United States, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

New York, NY
January 24, 2000

Consolidated Statement of Income

For the Years Ended December 31, 1999, 1998 & 1997

(In Thousands of Dollars except per share amount)	1999	1998	1997
OPERATING REVENUES (NOTE G)	$679,975	$686,191	$709,029
OPERATING EXPENSES			
Operation			
Fuel and energy	159,403	151,544	182,666
Capacity purchased	33,873	34,515	39,976
Other (Note G)	147,709	146,058	158,600
Maintenance	37,987	42,888	42,203
Depreciation (Note G)	57,351	82,809	74,618
Amortization of cancelled nuclear project, deferred return and regulatory tax asset (Note D and J)	36,393	13,758	13,758
Income taxes (Note A and F)	66,564	53,619	40,833
Other taxes (Note G)	47,140	64,674	52,493
TOTAL	586,420	589,865	605,147
OPERATING INCOME	93,555	96,326	103,882
OTHER INCOME AND (DEDUCTIONS)			
Allowance for equity funds used during construction	575	13	336
Other-net (Note G)	(838)	1,097	1,361
Non-operating income taxes	4,664	3,848	3,678
TOTAL	4,401	4,958	5,375
INCOME BEFORE INTEREST CHARGES	97,956	101,284	109,257
INTEREST CHARGES			
Interest on long-term debt	42,104	50,129	63,063
Interest on Seabrook obligation bonds owned by the company	(6,844)	(7,293)	(6,905)
Dividend requirement of mandatorily redeemable securities	4,813	4,813	4,813
Other interest (Note G)	4,927	6,507	3,280
Allowance for borrowed funds used during construction	(1,660)	(455)	(1,239)
	43,340	53,701	63,012
Amortization of debt expense and redemption premiums	2,392	2,511	2,788
NET INTEREST CHARGES	45,732	56,212	65,800
NET INCOME	52,224	45,072	43,457
Premium (Discount) on preferred stock redemptions	53	(21)	(48)
Dividends on preferred stock	66	201	205
INCOME APPLICABLE TO COMMON STOCK	$ 52,105	$ 44,892	$ 43,300
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING – BASIC	14,052	14,018	13,976
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING – DILUTED	14,055	14,023	13,992
EARNINGS PER SHARE OF COMMON STOCK – BASIC	$ 3.71	$ 3.20	$ 3.10
EARNINGS PER SHARE OF COMMON STOCK – DILUTED	$ 3.71	$ 3.20	$ 3.09
CASH DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 2.88	$ 2.88	$ 2.88

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Statement of Cash Flows

For the Years Ended December 31, 1999, 1998 & 1997

(In Thousands of Dollars)	1999	1998	1997
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 52,224	$ 45,072	$ 43,457
Adjustments to reconcile net income			
to net cash provided by operating activities:			
Depreciation and amortization	83,374	88,099	79,487
Deferred income taxes	17,451	3,074	6,804
Deferred income taxes-generation asset sale	(70,222)	–	–
Deferred investment tax credits – net	(468)	(762)	(762)
Amortization of nuclear fuel	8,425	6,892	5,799
Allowance for funds used during construction	(2,235)	(468)	(1,575)
Amortization of deferred return	12,586	12,586	12,586
Changes in:			
Accounts receivable – net	8,749	(14,889)	17,626
Fuel, materials and supplies	(1,202)	(14,466)	2,863
Prepayments	4,368	(4,027)	211
Accounts payable	2,025	(9,782)	8,404
Interest accrued	(1,770)	(63)	(3,569)
Taxes accrued	(6,446)	4,849	3,116
Other assets and liabilities	(8,386)	(4,062)	(1,644)
Total Adjustments	46,249	66,981	129,346
NET CASH PROVIDED BY OPERATING ACTIVITIES	98,473	112,053	172,803
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock	1,157	4,923	(6,432)
Long-term debt	25,000	199,636	98,500
Notes payable	(69,761)	49,141	26,786
Securities redeemed and retired:			
Preferred stock	(4,299)	(52)	(110)
Long-term debt	(218,008)	(222,348)	(151,199)
(Premium) Discount on preferred stock redemption	(53)	21	48
Expenses of issues	(550)	(1,600)	(1,500)
Lease obligations	(348)	(339)	(315)
Dividends			
Preferred stock	(116)	(202)	(206)
Common stock	(40,450)	(40,285)	(40,408)
NET CASH USED IN FINANCING ACTIVITIES	(307,428)	(11,105)	(74,836)
CASH FLOWS FROM INVESTING ACTIVITIES			
Investment in unregulated businesses	(88,489)	–	–
Net cash received from sale of generation assets	270,590	–	–
Plant expenditures, including nuclear fuel	(34,772)	(38,040)	(33,436)
Investment in debt securities	5,447	8,528	(34,541)
NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES	152,776	(29,512)	(67,977)
CASH AND TEMPORARY CASH INVESTMENTS:			
NET CHANGE FOR THE PERIOD	(56,179)	71,436	29,990
BALANCE AT BEGINNING OF PERIOD	124,501	53,065	23,075
BALANCE AT END OF PERIOD	68,322	124,501	53,065
LESS: RESTRICTED CASH	29,223	26,812	23,392
BALANCE: UNRESTRICTED CASH AND TEMPORARY CASH INVESTMENTS	$ 39,099	$ 97,689	$ 29,673
CASH PAID DURING THE PERIOD FOR:			
Interest (net of amount capitalized)	$ 40,020	$ 51,481	$ 59,441
Income taxes	$121,450	$ 42,450	$ 26,773

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Balance Sheet

Assets

December 31, 1999 and 1998

(In Thousands of Dollars)	1999	1998
UTILITY PLANT AT ORIGINAL COST		
In service	$1,007,065	$1,886,930
Less, accumulated provision for depreciation	532,409	714,375
	474,656	1,172,555
Construction work in progress	25,708	33,695
Nuclear fuel	21,101	20,174
NET UTILITY PLANT	521,465	1,226,424
OTHER PROPERTY AND INVESTMENTS		
Investment in generation facility	83,494	–
Nuclear decommissioning trust fund assets	28,255	23,045
Other	20,098	14,828
	131,847	37,873
CURRENT ASSETS		
Unrestricted cash and temporary cash investments	39,099	97,689
Restricted cash	29,223	26,812
Accounts receivable		
Customers, less allowance for doubtful accounts of $1,800 and $1,800	56,057	54,178
Other, less allowance for doubtful accounts of $508 and $631	53,612	64,240
Accrued utility revenues	25,019	21,079
Fuel, materials and supplies, at average cost	9,259	33,613
Prepayments	3,056	7,424
Other	4,801	154
TOTAL	220,126	305,189
DEFERRED CHARGES		
Unamortized debt issuance expenses	8,688	9,421
Other	6,099	1,664
TOTAL	14,787	11,085
REGULATORY ASSETS (future amounts due from customers through the ratemaking process)		
Nuclear plant investments-above market	518,268	–
Income taxes due principally to book-tax differences (Note A)	166,965	264,811
Long-term purchase power contracts-above market	144,406	–
Connecticut Yankee	37,013	42,633
Unamortized redemption costs	22,314	23,468
Unamortized cancelled nuclear project	8,780	10,952
Displaced worker protection costs	5,746	–
Uranium enrichment decommissioning costs	1,040	1,177
Deferred return – Seabrook Unit 1	–	12,586
Other	5,453	4,962
TOTAL	909,985	360,589
	$1,798,210	$1,941,160

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Balance Sheet

Capitalization & Liabilities

December 31, 1999 and 1998

(In Thousands of Dollars)	1999	1998
CAPITALIZATION (NOTE B)		
Common stock equity		
Common stock (no par value, 14,062,502 and 14,034,562 shares outstanding in 1999 and 1998)	$ 292,006	$ 292,006
Paid-in capital	2,253	2,046
Capital stock expense	(2,170)	(2,182)
Unearned employee stock ownership plan equity	(9,261)	(10,210)
Retained earnings	175,470	163,847
	458,298	445,507
Preferred stock	–	4,299
Company-obligated mandatorily redeemable securities of subsidiary holding solely parent debentures	50,000	50,000
Long-term debt		
Long-term debt	605,641	757,370
Investment in Seabrook obligation bonds	(87,413)	(92,860)
Net long-term debt	518,228	664,510
TOTAL	1,026,526	1,164,316
NONCURRENT LIABILITIES		
Purchase power contract obligation	144,406	–
Nuclear decommissioning obligation	28,255	23,045
Connecticut Yankee contract obligation	27,056	32,711
Pensions accrued (Note H)	19,026	31,097
Obligations under capital leases	16,131	16,506
Other	10,394	6,622
TOTAL	245,268	109,981
CURRENT LIABILITIES		
Current portion of long-term debt	25,000	66,202
Notes payable	17,131	86,892
Accounts payable	49,069	48,749
Accounts payable – APS customers	56,220	54,515
Dividends payable	10,125	10,155
Taxes accrued	2,570	9,015
Interest accrued	8,433	10,203
Obligations under capital leases	375	348
Other accrued liabilities	39,421	39,845
TOTAL	208,344	325,924
CUSTOMERS' ADVANCES FOR CONSTRUCTION	1,867	1,867
REGULATORY LIABILITIES (future amounts owed to customers through the ratemaking process)		
Accumulated deferred investment tax credits	15,157	15,623
Deferred gains on sale of property	15,901	4
Customer refund	18,381	–
Other	2,543	2,061
TOTAL	51,982	17,688
DEFERRED INCOME TAXES (future tax liabilities owed to taxing authorities)	264,223	321,384
COMMITMENTS AND CONTINGENCIES (NOTE L)		
	$1,798,210	$1,941,160

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

Consolidated Statement of Changes in Shareholders' Equity

For the Years Ended December 31, 1999, 1998 & 1997	Common Stock Shares[a]	Common Stock Amount	Preferred Stock Shares[b]	Preferred Stock Amount	Paid-in Capital	Capital Stock Expense	Unearned ESOP Equity	Retained Earnings	Total
Balance as of December 31, 1996	14,101,291	$284,579	44,612	$4,461	$772	$(2,182)	—	$156,299	$443,929
Net income for 1997								43,457	43,457
Cash dividends on common stock – $2.88 per share								(40,255)	(40,255)
Cash dividends on preferred stock								(205)	(205)
Issuance of 134,844 shares common stock – no par value	134,833	4,151			577				4,728
ESOP purchase of 328,300 common shares	(328,300)						(11,160)		(11,160)
Repurchase and cancellation of preferred stock			(1,103)	(110)					(110)
Discount on preferred stock repurchase								48	48
Balance as of December 31, 1997	13,907,824	288,730	43,509	4,351	1,349	(2,182)	(11,160)	159,344	440,432
Net income for 1998								45,072	45,072
Cash dividends on common stock – $2.88 per share								(40,389)	(40,389)
Cash dividends on preferred stock								(201)	(201)
Issuance of 98,798 shares common stock – no par value	98,798	3,276			459				3,735
Allocation of benefits – ESOP	27,940				238		950		1,188
Repurchase and cancellation of preferred stock			(524)	(52)					(52)
Discount on preferred stock repurchase								21	21
Balance as of December 31, 1998	14,034,562	292,006	42,985	4,299	2,046	(2,182)	(10,210)	163,847	449,806
Net income for 1999								52,224	52,224
Cash dividends on common stock – $2.88 per share								(40,470)	(40,470)
Cash dividends on preferred stock								(66)	(66)
Allocation of benefits – ESOP	27,940				207		949		1,156
Repurchase and cancellation of preferred stock			(42,985)	(4,299)		12		(12)	(4,299)
Premium on preferred stock repurchase								(53)	(53)
Balance as of December 31, 1999	14,062,502	$292,006	0	$0	$2,253	($2,170)	($9,261)	$175,470	$458,298

(a) There were 30,000,000 shares authorized in 1999, 1998 and 1997

(b) There were 1,119,612 shares authorized in 1999, 1998 and 1997

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

The United Illuminating Company (the Company) is an operating electric public utility company, engaged principally in the purchase, transmission, distribution and sale of electricity for residential, commercial and industrial purposes in a service area of about 335 square miles in the southwestern part of the State of Connecticut. The service area, largely urban and suburban in character, includes the principal cities of Bridgeport (population approximately 137,000) and New Haven (population approximately 124,000) and their surrounding areas. Situated in the service area are retail trade and service centers, as well as large and small industries producing a wide variety of products, including helicopters and other transportation equipment, electrical equipment, chemicals and pharmaceuticals.

In addition, the Company has created, and owns, unregulated subsidiaries. The Company has one wholly-owned subsidiary, United Resources, Inc. (URI), that serves as the parent corporation for several unregulated businesses, each of which is incorporated separately to participate in business ventures that will complement the Company's regulated electric utility business and provide long-term rewards to the Company's shareowners.

URI has four wholly-owned subsidiaries. American Payment Systems, Inc. manages a national network of agents for the processing of bill payments made by customers of the Company and other companies. Another subsidiary of URI, United Capital Investments, Inc., and its subsidiaries, participate in business ventures that complement the Company's business. A third URI subsidiary, Precision Power, Inc. and its subsidiaries, provide specialty electrical, telecommunications and mechanical contracting and power-related services to the owners of commercial buildings and industrial and institutional facilities. URI's fourth subsidiary, United Bridgeport Energy, Inc., is a participant in a merchant wholesale electric generating facility located in Bridgeport, Connecticut.

(A) Statement of Accounting Policies

ACCOUNTING RECORDS The accounting records are maintained in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the Connecticut Department of Public Utility Control (DPUC).

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

PRINCIPLES OF CONSOLIDATION The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, United Resources, Inc. Intercompany accounts and transactions have been eliminated in consolidation.

REGULATORY ACCOUNTING Generally accepted accounting principles for regulated entities in the United States allow the Company to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS No. 71, the Company has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. In addition to the Regulatory Assets and Liabilities separately identified on the Consolidated Balance Sheet, there are other regulatory assets and liabilities such as conservation and load management costs and certain deferred tax liabilities. The Company also has obligations under long-term power contracts, the recovery of which is subject to regulation. If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable

(A) Statement of Accounting Policies (continued)

and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs are not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71.

The Restructuring Act enacted in Connecticut in 1998 provides for the Company to recover previously deferred costs through ongoing assessments to be included in future regulated service rates. See Note (C), "Rate-Related Regulatory Proceedings" for a discussion of the nature, amount and timing of recovery of the Company's stranded costs associated with the generation portion of its assets and operations, as well as a discussion of the regulatory decisions that provide for such recovery. Based on these regulatory decisions, the sale of the Company's fossil-generation assets in the second quarter of 1999, the planned divestiture of its nuclear generation ownership interests by the end of 2003, and, in anticipation of the Restructuring Act becoming effective on January 1, 2000, on December 31, 1999 the Company discontinued applying SFAS No. 71 to the generation portion of its assets and operations. However, based on the recovery mechanism that allows recovery of all of its stranded costs through its standard offer rates, the Company was not required to take any write-offs in connection with this event. The Company expects to continue to meet the criteria for application of SFAS No. 71 for the remaining portion of its assets and operations for the foreseeable future. If a change in accounting were to occur to the non-generation portion of the Company's operations, it could have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well.

UTILITY PLANT The cost of additions to utility plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The cost of current repairs and minor replacements is charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

The Company's utility plant in service as of December 31, 1999 and 1998 was comprised as follows:

(In Thousands)	1999	1998
Production (1)	$ 271,012	$1,133,984
Transmission (1)	148,419	161,643
Distribution	415,892	408,845
General (1)	46,578	56,264
Future use plant	30,167	30,505
Other (1)	94,997	95,689
	$1,007,065	$1,886,930

(1) As of December 31, 1999, the Company had reclassified $496.9 million of production plant, $7.4 million of transmission plant, $7.5 million of general plant and $0.6 million of other plant associated with its nuclear entitlements from utility plant in service to a regulatory asset.

See Note (C), "Rate-related Regulatory Proceedings" for a discussion of the sale by the Company of its two operating fossil-fueled generating stations and the regulatory decisions allowing for recovery of stranded costs, including the above-market investment in nuclear generating units.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION In accordance with the uniform systems of accounts, the Company capitalizes AFUDC, which represents the approximate cost of debt and equity capital devoted to plant under construction. The portion of the allowance applicable to borrowed funds is presented in the Consolidated Statement of Income as a reduction of interest charges, while the portion of the allowance applicable to equity funds is presented as other income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. The Company compounds the allowance applicable to major construction projects semi-annually. Weighted average AFUDC rates in effect for 1999, 1998 and 1997 were 7.75%, 7.0% and 7.5%, respectively.

DEPRECIATION Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives determined by independent engineers. One-half year's depreciation is taken in the year of addition and disposition of utility plant, except in the case of major operating units on which depreciation commences in the month they are placed in service and ceases in the month they are removed from service. The aggregate annual provisions for depreciation for the years 1999, 1998 and 1997 were equivalent to approximately 3.10%, 3.26% and 3.15%, respectively, of the original cost of depreciable property.

INCOME TAXES In accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes," the Company has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, the Company has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences.

For ratemaking purposes, the Company normalizes all investment tax credits (ITC) related to recoverable plant investments except for the ITC related to Seabrook Unit 1, which was taken into income in accordance with provisions of a 1990 DPUC retail rate decision.

ACCRUED UTILITY REVENUES The estimated amount of utility revenues (less related expenses and applicable taxes) for service rendered but not billed is accrued at the end of each accounting period.

CASH AND TEMPORARY CASH INVESTMENTS For cash flow purposes, the Company considers all highly liquid debt instruments with a maturity of three months or less at the date of purchase to be cash and temporary cash investments.

The Company is required to maintain an operating deposit with the project disbursing agent related to its 17.5% ownership interest in Seabrook Unit 1. This operating deposit, which is the equivalent to one and one half months of the funding requirement for operating expenses, is restricted for use and amounted to $2.3 million and $3.8 million at December 31, 1999 and 1998, respectively.

The Company's wholly-owned subsidiary, American Payment Systems, Inc., maintains separate bank accounts for holding cash received from clients' customers before the amounts are transferred to clients. The amount of this restricted cash at December 31, 1999 and 1998 was $26.9 million and $23.1 million, respectively.

At December 31, 1999, the Company included in the cash balance $25 million of proceeds from the issuance by the Business Finance Authority of the State of New Hampshire of $25 million principal amount of tax-exempt Pollution Control Refunding Revenue Bonds that were held by a trustee.

(A) Statement of Accounting Policies (continued)

INVESTMENTS The Company's investment in the Connecticut Yankee Atomic Power Company, a nuclear generating company in which the Company has a 9 1/2% stock interest, is accounted for on an equity basis. This investment amounted to $10.0 million and $9.9 million at December 31, 1999 and 1998, respectively, and is included on the Consolidated Balance Sheet as a regulatory asset. See Note (L), "Commitments and Contingencies – Other Commitments and Contingencies - Connecticut Yankee."

RESEARCH AND DEVELOPMENT COSTS Research and development costs, including environmental studies, are charged to expense as incurred.

PENSION AND OTHER POSTEMPLOYMENT BENEFITS The Company accounts for normal pension plan costs in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions," and for supplemental retirement plan costs and supplemental early retirement plan costs in accordance with the provisions of SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits."

The Company accounts for other postemployment benefits, consisting principally of health and life insurance, under the provisions of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," which requires, among other things, that the liability for such benefits be accrued over the employment period that encompasses eligibility to receive such benefits. The annual incremental cost of this accrual has been allowed in retail rates in accordance with a 1992 rate decision of the DPUC.

URANIUM ENRICHMENT OBLIGATION Under the Energy Policy Act of 1992 (Energy Act), the Company will be assessed for its proportionate share of the costs of the decontamination and decommissioning of uranium enrichment facilities operated by the Department of Energy. The Energy Act imposes an overall cap of $2.25 billion on the obligation assessed to the nuclear utility industry and limits the annual assessment to $150 million each year over a 15-year period. The Company has recovered these assessments in rates as a component of fuel expense. Accordingly, the Company has recognized the unrecovered costs as a regulatory asset on its Consolidated Balance Sheet. At December 31, 1999, the Company's remaining share of the obligation, based on its ownership and leasehold interests in Seabrook Unit 1 and Millstone Unit 3, was approximately $1.0 million.

NUCLEAR DECOMMISSIONING TRUSTS External trust funds are maintained to fund the estimated future decommissioning costs of the nuclear generating units in which the Company has an ownership interest. These costs are accrued as a charge to depreciation expense over the estimated service lives of the units and are recovered in rates on a current basis. The Company paid $4.0 million, $2.6 million and $2.6 million during 1999, 1998 and 1997 into the decommissioning trust funds for Seabrook Unit 1 and Millstone Unit 3. At December 31, 1999, the Company's shares of the trust fund balances, which included accumulated earnings on the funds, were $20.5 million and $7.8 million for Seabrook Unit 1 and Millstone Unit 3, respectively. These fund balances are included in "Other Property and Investments" and the accrued decommissioning obligation is included in "Noncurrent Liabilities" on the Company's Consolidated Balance Sheet.

IMPAIRMENT OF LONG-LIVED ASSETS Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets to Be Disposed Of" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. This standard also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining allowable costs. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of SFAS No. 71 must be assessed on an ongoing basis. The Company does not have any assets that are impaired under this standard.

EARNINGS PER SHARE The following table presents a reconciliation of the numerators and denominators of the basic and diluted earnings per share calculations for the years 1999, 1998 and 1997:

(In Thousands, Except Per Share Amounts)	Income Applicable to Common Stock (Numerator)	Average Number of Shares Outstanding (Denominator)	Earnings per Share
1999			
Basic earnings per share	$52,105	14,052	$3.71
Effect of dilutive stock options	–	3	(.00)
Diluted earnings per share	$52,105	14,055	$3.71
1998			
Basic earnings per share	$44,892	14,018	$3.20
Effect of dilutive stock options	–	5	(.00)
Diluted earnings per share	$44,892	14,023	$3.20
1997			
Basic earnings per share	$43,300	13,976	$3.10
Effect of dilutive stock options	–	16	(.01)
Diluted earnings per share	$43,300	13,992	$3.09

STOCK-BASED COMPENSATION The Company accounts for employee stock-based compensation in accordance with Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." This statement establishes financial accounting and reporting standards for stock-based employee compensation plans, such as stock purchase plans, stock options, restricted stock, and stock appreciation rights. The statement defines the methods of determining the fair value of stock-based compensation and requires the recognition of compensation expense for book purposes. However, the statement allows entities to continue to measure compensation expense in accordance with the prior authoritative literature, APB No. 25, "Accounting for Stock Issued to Employees," but requires that pro forma net income and earnings per share be disclosed for each year for which an income statement is presented as if SFAS No. 123 had been applied. The accounting requirements of this statement are effective for transactions entered into after 1995. However, pro forma disclosures must include the effects of all awards granted after January 1, 1995. As of December 31, 1999, there were no options to which this statement would apply. Options granted in 1999 are not yet exercisable.

NEW ACCOUNTING STANDARDS On January 1, 1998, the Company adopted Statement of Financial Standards (SFAS) No. 130, "Reporting Comprehensive Income," which provides authoritative guidance on the reporting and display of comprehensive income and its components. For the years ended December 31, 1999, 1998 and 1997 comprehensive income was equal to net income as reported.

On January 1, 1998, the Company adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," which provides guidance about segment reporting. As described in Note (P), "Segment Information," the Company has only one reportable segment, that of regulated generation, distribution and sale of electricity.

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This statement, which is effective for fiscal quarters of fiscal years beginning after June 15, 2000, establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires entities to recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for the changes in the fair value of a derivative (gains and losses) would depend on the intended use and designation of the derivative. The Company cannot reasonably assess what effect applying SFAS No. 133 will have on its financial condition and results of operations in the future.

(B) Capitalization

COMMON STOCK The Company had 14,334,922 shares of its common stock, no par value, outstanding at December 31, 1999 and 1998, of which 272,420 shares and 300,360 shares were unallocated shares held by the Company's Employee Stock Ownership Plan (ESOP) and not recognized as outstanding for accounting purposes as of December 31, 1999 and 1998, respectively.

In 1990, the Company's Board of Directors and the shareowners approved a stock option plan for officers and key employees of the Company. The plan provides for the awarding of options to purchase up to 750,000 shares of the Company's common stock over periods of from one to ten years following the dates when the options are granted. The Connecticut Department of Public Utility Control (DPUC) has approved the issuance of 500,000 shares of stock pursuant to this plan. The exercise price of each option cannot be less than the market value of the stock on the date of the grant. Options to purchase 3,500 shares of stock at an exercise price of $30 per share, 7,800 shares of stock at an exercise price of $39.5625 per share, and 5,000 shares of stock at an exercise price of $42.375 per share have been granted by the Board of Directors and remained outstanding at December 31, 1999. No options were exercised during 1999.

	1999		1998		1997	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance – Beginning of Year	16,300	$38.37	115,098	$33.90	252,331	$32.20
Granted	–	–	–	–	–	–
Forfeited	–	–	–	–	(2,400)	$30.75
Exercised	–	–	(98,798)	$33.16	(134,833)	$30.79
Balance – End of Year	16,300	$38.37	16,300	$38.37	115,098	$33.90
Exercisable at End of Year	16,300	$38.37	16,300	$38.37	96,698	$34.51

On March 22, 1999, the Company's Board of Directors approved a stock option plan for directors, officers and key employees of the Company. The plan provides for the awarding of options to purchase up to 650,000 shares of the Company's common stock over periods of from one to ten years following the dates when the options are granted. The exercise price of each option cannot be less than the market value of the stock on the date of the grant. On June 28, 1999, the Company's shareowners approved the plan. Options to purchase 137,000 shares of stock at an exercise price of $43 7/32 per share have been granted by the Board of Directors and remained outstanding at December 31, 1999. No options to purchase shares of the Company's common stock can be exercised without the approval of the DPUC; and, as December 31, 1999, the Company had not requested approval by the DPUC.

On February 23, 1998, the Board of Directors granted 80,000 "phantom" stock options to Nathaniel D. Woodson upon his appointment as President of the Company. On each of the first five anniversaries of the grant date, 16,000 phantom stock options become exercisable and can be exercised at any time within Mr. Woodson's period of employment with the Company by means of the Company paying him the difference between the prevailing market price for each share and the phantom stock option price of $45.16 per share. At ten years after the grant date any unexercised phantom stock options will expire. At December 31, 1999, 16,000 phantom stock options were exercisable. Due to the immaterial effect on results of operations, no expense was recognized with regard to the phantom stock options.

The Company has entered into an arrangement under which it loaned $11.5 million to The United Illuminating Company Employee Stock Ownership Plan (ESOP). The trustee for the ESOP used the funds to purchase shares of the Company's common stock in open market transactions. The shares will be allocated to employees' ESOP accounts, as the loan is repaid, to cover a portion of the Company's required ESOP contributions. The loan will be repaid by the ESOP over a twelve-year period, using the Company's contributions and dividends paid on the unallocated shares of the stock held by the ESOP. As of December 31, 1999, 272,420 shares, with a fair market value of $14.0 million, had been purchased by the ESOP and had not been committed to be released or allocated to ESOP participants.

RETAINED EARNINGS RESTRICTION The indenture under which $200 million principal amount of Notes are issued places limitations on the payment of cash dividends on common stock and on the purchase or redemption of common stock. Retained earnings in the amount of $117.3 million were free from such limitations at December 31, 1999.

PREFERRED AND PREFERENCE STOCK The par value of each of these issues was credited to the appropriate stock account and expenses related to these issues were charged to capital stock expense.

On April 8, 1999, the Company called for redemption all 10,370 shares of its outstanding $100 par value 4.35% Preferred Stock, Series A, all 17,158 shares of its outstanding $100 par value 4.72% Preferred Stock, Series B, all 12,745 shares of its outstanding $100 par value 4.64% Preferred Stock, Series C and all 2,712 shares of its outstanding $100 par value 5 5/8% Preferred Stock, Series D. The Company paid a redemption premium of $53,355 in effecting these redemptions, which were completed on May 14, 1999.

Shares of preferred stock have preferential dividend and liquidation rights over shares of common stock. Preferred shareholders are not entitled to general voting rights. However, if any preferred dividends are in arrears for six or more quarters, or if certain other events of default occur, preferred shareholders are entitled to elect a majority of the Board of Directors until all preferred dividend arrearages are paid and any event of default is remedied. There were no shares of preferred stock outstanding at December 31, 1999.

Preference stock is a form of stock that is junior to preferred stock but senior to common stock. It is not subject to the earnings coverage requirements or minimum capital and surplus requirements governing the issuance of preferred stock. There were no shares of preference stock outstanding at December 31, 1999.

COMPANY-OBLIGATED MANDATORILY REDEEMABLE SECURITIES OF SUBSIDIARY HOLDING SOLELY PARENT DEBENTURES United Capital Funding Partnership L.P. (United Capital) is a special purpose limited partnership in which the Company owns all of the general partner interests. United Capital has issued $50 million of 9 5/8% Preferred Capital Securities, Series A, (Preferred Securities), the dividends on which are accrued and paid monthly.

The sole holding of United Capital is the $50 million of 9 5/8% Junior Subordinated Deferrable Interest Debentures, Series A, due April 30, 2025, (the Series A Debentures) issued by United Illuminating in 1995.

Holders of the Preferred Securities will be entitled to receive, to the extent of funds held by United Capital, cumulative preferential dividends, at an annual rate 9 5/8% of the liquidation preference of $25 per security, payable monthly in arrears on the last day of each calendar month. The payment of dividends and payments on redemption with respect to the Preferred Securities to the extent of funds held by United Capital, will be guaranteed under a Payment and Guarantee Agreement (the Guarantee) of United Illuminating. The Guarantee does not cover payment of amounts in respect of the Preferred Securities to the extent that United Capital does not have available funds for the payment thereof and cash on hand sufficient to make such payment.

(B) Capitalization (continued)

Such funds and cash on hand will be limited to payments by United Illuminating on the Series A Debentures. If United Illuminating fails to make interest payments on the Series A Debentures, United Capital will have insufficient funds to pay dividends on the Preferred Securities and the Guarantee will not cover payment of dividends.

The Preferred Securities are subject to mandatory redemption when the Series A Debentures mature or are redeemed.

LONG-TERM DEBT

(In Thousands) December 31,	1999	1998
OTHER LONG-TERM DEBT		
Pollution Control Revenue Bonds:		
4.35%, 1996 Series, due June 26, 2026 (1)	$ 7,500	$ 7,500
8%, 1989 Series A, due December 1, 2014	25,000	25,000
5 7/8%, 1993 Series, due October 1, 2033	64,460	64,460
Pollution Control Refunding Revenue Bonds:		
4.35%, 1997 Series, due July 30, 2027 (2)	27,500	27,500
4.55%, 1997 Series, due July 30, 2027 (1)	71,000	71,000
5.40%, 1999 Series, due December 1, 2029 (3)	25,000	–
Notes:		
6.20%, 1993 Series H, due January 15, 1999	–	66,202
6.25%, 1998 Series I, due December 15, 2002	100,000	100,000
6.00%, 1998 Series J, due December 15, 2003	100,000	100,000
Term Loans:		
6.95%, due August 29, 2000 (4)	–	50,000
6.4375%, due September 6, 2000 (4)	–	20,000
6.675%, due October 25, 2001 (4)	–	25,000
7.005%, due October 25, 2001 (4)	–	50,000
Obligation under the Seabrook Unit 1 sale/leaseback agreement	210,424	217,230
	630,884	823,892
Unamortized debt discount less premium	(243)	(320)
	630,641	823,572
Less:		
Current portion included in Current Liabilities	25,000	66,202
Investment-Seabrook Lease Obligation Bonds	87,413	92,860
Total Long-Term Debt	$518,228	$664,510

(1) The interest rate for these Bonds was fixed on February 1, 1999 for the five-year period ending January 30, 2004. Prior to February 1, 1999, the interest rate was variable.

(2) The interest rate for these Bonds was fixed on February 1, 1999 for the three-year period ending January 30, 2002. Prior to February 1, 1999, the interest rate was variable.

(3) The interest rate for these Bonds was fixed on December 16, 1999 for the three-year period ending December 1, 2002.

(4) The fixed interest rate for these variable interest rate term loans reflected the effect of the associated interest rate swaps.

On January 16, 1999, the Company repaid $66.2 million principal amount of 6.20% Notes at maturity.

On February 1, 1999, the Company converted $7.5 million principal amount of Connecticut Development Authority Bonds from a weekly reset mode to a five-year multiannual mode. The interest rate on the Bonds for the five-year period beginning February 1, 1999 is 4.35% and interest is payable semi-annually on August 1 and February 1. In addition, on February 1, 1999, the Company converted $98.5 million principal amount Business Finance Authority of the State of New Hampshire Bonds from a weekly reset mode to a multiannual mode. The interest rate on $27.5 million principal amount of the Bonds is 4.35% for a three-year period beginning February 1, 1999. The interest rate on $71 million principal amount of the Bonds is 4.55% for a five-year period. Interest on the Bonds is payable semi-annually on August 1 and February 1.

On March 8, 1999, the Company prepaid and terminated $20 million of the remaining $70 million outstanding debt under its $150 million Term Loan Agreement dated August 29, 1995. On April 16, 1999, the Company prepaid and terminated the entire remaining $50 million outstanding debt under said $150 million Term Loan Agreement, and the entire $75 million outstanding debt under its Term Loan Agreement dated October 25, 1996.

On December 16, 1999, the Company borrowed $25 million from the Business Finance Authority of the State of New Hampshire (BFA), representing the proceeds from the issuance by the BFA of $25 million principal amount of tax-exempt Pollution Control Refunding Revenue Bonds (PCRRBs). The Company is obligated, under its borrowing agreement with the BFA, to pay to a trustee for the PCRRBs' bondholders such amounts as will pay, when due, the principal of and the premium, if any, and interest on the PCRRBs. The PCRRBs will mature in 2029, and their interest rate is fixed at 5.4% for the three-year period ending December 1, 2002. At December 31, 1999, these proceeds were held by a trustee and were recognized as cash and long-term debt on the Consolidated Balance Sheet. The Company has used the proceeds of this $25 million borrowing to cause the redemption and repayment of $25 million of 8.0%, 1989 Series A, Pollution Control Revenue Bonds, an outstanding series of tax-exempt bonds on which the Company also had a payment obligation to a trustee for the bondholders. Expenses associated with this transaction, including redemption premiums totaling $750,000 and other expenses of approximately $417,000, were paid by the Company.

The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

Maturities and mandatory redemptions/repayments are set forth below:

(In Thousands)	2000	2001	2002	2003	2004
Maturities	$ –	$ –	$100,000	$100,000	$ –

(C) Rate-Related Regulatory Proceedings

On December 31, 1996, the DPUC completed a financial and operational review of the Company and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The DPUC did not change the existing retail base rates charged to customers, but the Rate Plan increased amortization of the Company's conservation and load management program investments during 1997-1998, and accelerated the amortization and recovery of unspecified assets during 1999-2001 if the Company's common stock equity return on utility investment exceeds 10.5% after recording the amortization. The Rate Plan also provided for retail price reductions of about 5%, compared to 1996 and phased-in over 1997-2001, primarily through reductions of conservation adjustment mechanism revenues, through a surcredit in each of the five plan years, and through acceptance of the Company's proposal to modify the operation of the fossil fuel clause mechanism. The Company's authorized return on utility common stock equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are to be utilized one-third for customer price reductions, one-third to increase amortization of assets, and one-third retained as earnings. As a result of the Rate Plan, customer prices were required to be reduced, on average, by 3% in 1997 compared to 1996. Also as a result of the Rate Plan, customer prices were required to be reduced by an additional 1% in 2000, and another 1% in 2001, compared to 1996. Retail revenues

(C) Rate-Related Regulatory Proceedings (continued)

decreased by approximately 7.0% through 1999 compared to 1996 due to customer price reductions. The Rate Plan was reopened in 1998, in accordance with its terms, to determine the assets to be subjected to accelerated recovery in 1999. The DPUC decided on February 10, 1999 to subject $12.1 million of the Company's regulatory tax assets to accelerated recovery in 1999.

The Rate Plan includes a provision that it may be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut. On October 1, 1999, the DPUC issued its decision establishing the Company's standard offer customer rates, commencing January 1, 2000, at a level 10% below 1996 rates, as directed by the Restructuring Act described in detail below. These standard offer customer rates are in effect for the period 2000-2001 and supercede the rate reductions for this period that were included in the Rate Plan. The decision also reduced the required amount of accelerated amortization in 2000 and 2001. Under this decision, all other components of the Rate Plan are expected to remain in effect through 2001. The Connecticut Office of Consumer Counsel, the statutory representative of consumer interests in public utility matters, is contesting the DPUC's calculation of the level of the Company's 1996 rates in an appeal taken to the Superior Court from the DPUC's decision.

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. As a result of the Act, the business of generating and selling electricity directly to consumers is opened to competition. These business activities are separated from the business of delivering electricity to consumers, also known as the transmission and distribution business. The business of delivering electricity remains with the incumbent franchised utility companies (including the Company), which continues to be regulated by the DPUC as Distribution Companies. Since mid-1999, Distribution Companies have been required to separate on consumers' bills the electricity generation services component from the charge for delivering the electricity and all other charges.

A major component of the Restructuring Act is the collection, by Distribution Companies, of a "competitive transition assessment," a "systems benefits charge," an "energy conservation and load management program charge" and a "renewable energy investment charge." The competitive transition assessment represents costs that have been reasonably incurred by, or will be incurred by, Distribution Companies to meet their public service obligations as electric companies, and that will likely not otherwise be recoverable in a competitive generation and supply market. These costs include above-market long-term purchased power contract obligations, regulatory asset recovery and above-market investments in power plants (so-called stranded costs). The systems benefits charge represents public policy costs, such as generation decommissioning and displaced worker protection costs. Beginning in 2000, a Distribution Company must collect the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge from all Distribution Company customers.

The Restructuring Act requires that, in order for a Distribution Company to recover any stranded costs associated with its power plants, its fossil-fueled plants must be sold prior to 2000, with any net excess proceeds used to mitigate its recoverable stranded costs, and the Company must attempt to divest its ownership interests in its nuclear-fueled power plants prior to 2004.

On October 2, 1998, the Company agreed to sell both of its operating fossil-fueled generating stations, Bridgeport Harbor Station and New Haven Harbor Station, to Wisvest-Connecticut, LLC, a single-purpose subsidiary of Wisvest Corporation. Wisvest Corporation is a non-utility subsidiary of Wisconsin Energy Corporation, Milwaukee, Wisconsin. On April 16, 1999, the transaction closed and the Company received approximately $277.9 million from this sale. The Company realized a before-tax book gain of $86.5 million from the sale of these plant investments. However, under the Restructuring Act, this gain was offset by a writedown of the stranded costs eligible for collection by the Company under the Restructuring Act's competitive transition assessment, such that there was no net income effect of the sale. The Company used the net cash proceeds from the sale to reduce debt.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, and in other regulatory dockets, the Company stated that it plans to divest its nuclear generation ownership interests (17.5% of Seabrook Unit 1 in New Hampshire and 3.685% of Millstone Station Unit 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. The DPUC is currently considering the Company's plan for divesting its ownership interest in Millstone Unit 3 through an auction process to be conducted by a consultant to be selected by the DPUC. The divestiture process for Seabrook Unit 1 has not yet been determined. In anticipation of ultimate divestiture, the Company has satisfied the Restructuring Act's requirement that nuclear generating assets be separated from its transmission and distribution assets. This was accomplished by transferring the nuclear generating assets into a separate new division of the Company, using divisional financial statements and accounting to segregate all revenues, expenses, assets and liabilities associated with nuclear ownership interests. In a decision dated May 19, 1999, the DPUC approved the Company's proposal in this regard.

The Company's unbundling plan also proposes to separate its ongoing regulated transmission and distribution operations and functions, that is, the Distribution Company assets and operations, from all of its unregulated operations and activities. This would be achieved by undergoing a corporate restructuring into a holding company structure. In the holding company structure proposed, the Company will become a wholly-owned subsidiary of a holding company, and each share of the common stock of the Company will be converted into a share of common stock of the holding company. In connection with the formation of the holding company structure, all of the Company's interests in all of its operating unregulated subsidiaries will be transferred to the holding company and, to the extent new businesses are subsequently acquired or commenced, they will also be financed and owned by the holding company. An application for the DPUC's approval of this corporate restructuring was filed on November 13, 1998 and, in a decision dated May 19, 1999, the DPUC approved the proposed corporate restructuring. The Company has filed applications with the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission seeking approval of the proposed corporate restructuring, and a special meeting of the Company's shareowners will be held on March 17, 2000 to vote on approval of the restructuring.

On March 24, 1999, the Company applied to the DPUC for a calculation of the Company's stranded costs that will be recovered by it in the future through the competitive transition assessment under the Restructuring Act. In a decision dated August 4, 1999, the DPUC determined that the Company's stranded costs total $801.3 million, consisting of $160.4 million of above-market long-term purchased power contract obligations, $153.3 million of generation-related regulatory assets (net of related tax and accounting offsets), and $487.6 million of above-market investments in nuclear generating units (net of $26.4 million of gains from generation asset sales and other offsets related to generation assets). The DPUC decision provides that these stranded cost amounts are subject to true-ups, adjustments and potential additional future offsets, in accordance with the Restructuring Act. The Connecticut Office of Consumer Counsel, the statutory representative of consumer interests in public utility matters, is contesting the DPUC's calculation of the market value of the Company's generating assets in an appeal taken to the Superior Court from the DPUC's decision.

Under the Restructuring Act, retail customers representing a total of up to 35% of the Company's retail customer load became able to choose their power supply providers on and after January 1, 2000, and all of the Company's customers will be able to choose their power supply providers as of July 1, 2000. On and after January 1, 2000 and through December 31, 2003, the Company is required to offer fully-bundled "standard offer" electric service, under regulated rates, to all customers who do not choose an alternate power supply provider. The standard offer rates must include the fully-bundled price of generation, transmission and distribution services, the competitive transition assessment, the systems benefits charge and the conservation and renewable energy charges. The fully-bundled standard offer rates must also be at least 10% below the average fully-bundled prices in 1996.

(C) Rate-Related Regulatory Proceedings (continued)

In March of 1999, the DPUC commenced a proceeding to determine what the Company's standard offer rates should be under the above requirements of the Restructuring Act. In April, May and June of 1999, the Company filed descriptive material, data and supporting testimony with the DPUC setting forth the Company's overall approach for determining the components of its standard offer rates, and for continuation of the five-year Rate Plan ordered by the DPUC in its 1996 financial and operational review of the Company (see above) through the four-year standard offer period. On July 27, 1999, the Company and Enron Capital & Trade Resources Corp. (ECTR), an affiliate of Enron Corp., Houston, Texas (Enron) filed with the DPUC a joint stipulation and settlement proposal to resolve simultaneously all of the issues in the Company's standard offer rate proceeding. The proposal included an arrangement between the Company and ECTR whereby ECTR will supply all of the generation services needed by the Company to meet its standard offer obligations for the four-year standard offer period, and an assumption by ECTR of all of the Company's long-term purchased power agreement (PPA) obligations. The stipulation and settlement proposal also provided for the Company's standard offer rates at a fully-bundled level that complies with the 10% reduction required by the Restructuring Act, including the generation services component of these rates, the Company's stranded costs for purposes of future recovery, the competitive transition assessment, systems benefits charge, delivery (transmission and distribution) charges, and conservation, load management and renewable energy charges. The Company also requested that a purchased power adjustment clause authorized by the Restructuring Act be put in place to adjust standard offer rates for limited purposes, and that the Company's five-year Rate Plan, as modified and supplemented by the stipulation and settlement proposal, be continued during the four-year standard offer period. In its decision, dated October 1, 1999, on the Company's standard offer rates, the DPUC approved elements of the stipulation and settlement proposal, including the arrangements with ECTR, subject to specified changes, including changes in the level of the generation services component of customers' rates. On October 15, 1999, the Company filed its standard offer generation services component of rates in compliance with the DPUC's decision, and the Company and ECTR concurrently filed a revised stipulation and settlement proposal. These filings were approved by the DPUC on December 9, 1999 and, on December 28, 1999, the Company and Enron Power Marketing, Inc., another affiliate of Enron, entered into a Wholesale Power Supply Agreement, a PPA Entitlements Transfer Agreement and related agreements documenting the approved four-year standard offer power supply arrangement and the assumption of all of the Company's PPAs, effective January 1, 2000. From January 1, 2000 through June 30, 2000, EPMI will sell to the Company energy beyond that supplied by Wisvest as described above. The agreements also provide for the sale to EPMI of the Company's entitlements under all of its wholesale purchased power agreements (PPAs). However, unless or until a PPA is terminated or formally assigned to EPMI, the Company remains legally liable to pay the applicable power supplier all amounts due under the PPA. The agreements with EPMI also include a financially settled contract for differences related to certain call rights of EPMI and put rights of the Company with respect to the Company's entitlements in Seabrook Unit 1 and in Millstone Unit 3, and the Company's provision to EPMI of certain ancillary products and services associated with those nuclear entitlements, which provisions terminate at the earlier of December 31, 2003 or the date that the Company sells its nuclear interests. The agreements do not restrict the Company's right to sell to third parties the Company's ownership interests in those nuclear generation units or the generated energy actually attributable to its ownership interests.

Based on the decisions in the regulatory proceedings described above, the sale of the Company's fossil-generation assets in the second quarter of 1999, the planned divestiture of its nuclear generation ownership interests by the end of 2003, and in anticipation of the Restructuring Act becoming effective on January 1, 2000, the Company ceased applying SFAS No. 71 to the generation portion of its assets and operations as of December 31, 1999. Based on the favorable DPUC decisions that allow full recovery, through the Company's rates, of all historically incurred stranded costs, the Company did not record any write-offs in connection with this event.

(D) Accounting for Phase-in Plan

The Company phased into rate base its allowable investment in Seabrook Unit 1, amounting to $640 million, during the period January 1, 1990 to January 1, 1994. In conjunction with this phase-in plan, the Company was allowed to record a deferred return on the portion of allowable investment excluded from rate base during the phase-in period. The Company amortized the net-of-tax accumulated deferred return of $62.9 million over the five-year period that ended on December 31, 1999.

(E) Short-Term Credit Arrangements

The Company has a revolving credit agreement with a group of banks, which currently extends to December 7, 2000. The borrowing limit of this facility is $60 million. The facility permits the Company to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by the Eurodollar interbank market in London. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1999, the Company had $17 million in short-term borrowings outstanding under this facility.

The Company's long-term debt instruments do not limit the amount of short-term debt that the Company may issue. The Company's revolving credit agreement described above requires it to maintain an available earnings/interest charges ratio of not less than 1.5:1.0 for each 12-month period ending on the last day of each calendar quarter. For the 12-month period ended December 31, 1999, this coverage ratio was 4.7:1.0.

Information with respect to short-term borrowings under the Company's revolving credit agreements is as follows:

(In Thousands)	1999	1998	1997
Maximum aggregate principal amount of short-term borrowings outstanding at any month-end	$80,000	$130,000	$50,000
Average aggregate short-term borrowings outstanding during the year*	$45,300	$115,753	$41,441
Weighted average interest rate*	5.5%	6.1%	5.9%
Principal amounts outstanding at year-end	$17,000	$ 80,000	$30,000
Annualized interest rate on principal amounts outstanding at year-end	7.0%	5.7%	6.2%

*Average short-term borrowings represent the sum of daily borrowings outstanding, weighted for the number of days outstanding and divided by the number of days in the period. The weighted average interest rate is determined by dividing interest expense by the amount of average borrowings. Commitment fees of approximately $291,000 and $381,000 paid during 1999 and 1998, respectively, are excluded from the calculation of the weighted average interest rate.

(F) Income Taxes

(In Thousands)	1999	1998	1997
Income tax expense consists of:			
INCOME TAX PROVISIONS:			
Current			
Federal	$91,247	$36,774	$23,568
State	23,891	10,685	7,545
Total current	115,138	47,459	31,113
Deferred			
Federal	(39,767)	2,964	6,123
State	(13,004)	110	681
Total deferred	(52,771)	3,074	6,804
Investment tax credits	(467)	(762)	(762)
TOTAL INCOME TAX EXPENSE	$61,900	$49,771	$37,155
INCOME TAX COMPONENTS CHARGED AS FOLLOWS:			
Operating expenses	$66,564	$53,619	$40,833
Other income and deductions – net	(4,664)	(3,848)	(3,678)
TOTAL INCOME TAX EXPENSE	$61,900	$49,771	$37,155
The following table details the components of the deferred income taxes:			
Gain on sale of utility property	($70,573)	($697)	($272)
Tax depreciation on unrecoverable plant investment	5,902	6,291	8,089
Fossil plants decommissioning reserve	(116)	(329)	(7,286)(1)
Conservation & load management	(2,181)	(8,026)	(5,768)
Accelerated depreciation	4,996	5,449	5,681
Pension benefits	4,192	3,463	4,911
Seabrook sale/leaseback transaction	(69)	304	2,664
Cancelled nuclear project	(467)	(467)	(467)
Unit overhaul and replacement power costs	1,523	(1,157)	212
Displaced worker protection costs	2,329	–	–
Deferred fossil fuel costs	–	–	(686)
Bond redemption costs	(1,014)	(1,039)	172
Property tax settlement	834	(834)	–
Other	1,873	116	(446)
DEFERRED INCOME TAXES – NET	($52,771)	$3,074	$6,804

(1) $6,719 of this amount is for deferred income tax benefits from prior years.

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

(In Thousands)	1999		1998		1997	
	Pre-Tax	Tax	Pre-Tax	Tax	Pre-Tax	Tax
Computed tax at federal statutory rate		$ 39,943		$33,195		$28,214
Increases (reductions) resulting from:						
Deferred return-Seabrook Unit 1	12,586	4,405	12,586	4,405	12,586	4,405
ITC taken into income	(468)	(468)	(762)	(762)	(762)	(762)
Allowance for equity funds used during construction	(575)	(201)	(13)	(5)	(336)	(118)
Fossil plant decommissioning reserve	(262)	(92)	(723)	(253)	(15,591)	(5,457)
Amortization of regulatory asset	22,635	7,922	–	–	–	–
Book depreciation in excess of non-normalized tax depreciation	16,155	5,654	22,789	7,976	23,926	8,374
State income taxes, net of federal income tax benefits	10,887	7,076	10,795	7,017	8,226	5,345
Other items – net	(6,683)	(2,339)	(5,149)	(1,802)	(8,134)	(2,846)
Total income tax expense		$ 61,900		$49,771		$37,155
Book income before income taxes		$114,124		$94,843		$80,612
Effective income tax rates		54.2%		52.5%		46.1%

At December 31, 1999, the Company had deferred tax liabilities for taxable temporary differences of $352 million and deferred tax assets for deductible temporary differences of $88 million, resulting in a net deferred tax liability of $264 million. Significant components of deferred tax liabilities and assets were as follows: tax liabilities on book/tax plant basis differences and on the cumulative amount of income taxes on temporary differences previously flowed through to ratepayers, $215 million; tax liabilities on normalization of book/tax depreciation timing differences, $125 million and tax assets on the disallowance of plant costs, $35 million.

(G) Supplementary Information

(In Thousands)	1999	1998	1997
OPERATING REVENUES			
Retail	$ 639,596	$ 631,607	$ 622,333
Wholesale – capacity	2,235	11,524	9,747
– energy	22,099	33,424	73,124
Other	16,045	9,636	3,825
TOTAL OPERATING REVENUES	$ 679,975	$ 686,191	$ 709,029
SALES BY CLASS(MWH's) – UNAUDITED			
Retail			
Residential	2,053,927	1,924,724	1,899,284
Commercial	2,388,240	2,324,507	2,248,974
Industrial	1,161,856	1,154,935	1,168,470
Other	48,027	48,166	48,619
	5,652,050	5,452,332	5,365,347
Wholesale	1,009,866	1,551,109	2,700,393
TOTAL SALES	6,661,916	7,003,441	8,065,740
OTHER OPERATION EXPENSES			
Production	$ 20,850	$ 28,427	$ 26,203
Transmission & Distribution	42,336	35,681	36,926
Customer Service	26,923	26,582	28,957
Administrative & General	57,600	55,368	66,514
TOTAL	$ 147,709	$ 146,058	$ 158,600
DEPRECIATION			
Plant in service	$53,347	$ 67,143	$ 65,585
Accelerated conservation and load management	0	13,086	6,636
Nuclear decommissioning	4,004	2,580	2,397
	$ 57,351	$ 82,809	$ 74,618
OTHER TAXES			
Charged to:			
Operating:			
State gross earnings	$ 24,518	$ 24,039	$ 23,571
Local real estate and personal property (1)	17,745	35,088	22,974
Payroll taxes	4,877	5,547	5,948
	47,140	64,674	52,493
Nonoperating and other accounts	598	510	459
TOTAL OTHER TAXES	$ 47,738	$ 65,184	$ 52,952
OTHER INCOME AND (DEDUCTIONS) – NET			
Interest income	$ 1,801	$ 3,181	$ 2,317
Equity earnings from Connecticut Yankee	36	854	1,343
Loss from subsidiary companies (2)	(590)	(1,748)	(3,639)
Miscellaneous other income and (deductions) – net	(2,085)	(1,190)	1,340
TOTAL OTHER INCOME AND (DEDUCTIONS) – NET	($838)	$ 1,097	$ 1,361
OTHER INTEREST CHARGES			
Notes Payable	$ 2,662	$ 5,050	$ 2,462
Other	2,265	1,457	818
TOTAL OTHER INTEREST CHARGES	$ 4,927	$ 6,507	$ 3,280

(1) 1998 includes $14,025 charge for property tax settlement.

(2) Includes before-tax non-recurring charges in 1997 of $2,825 resulting from losses at American Payment Systems, Inc.

(H) Pension and Other Benefits

The Company's qualified pension plan, which is based on the highest three years of pay, covers substantially all of its employees, and its entire cost is borne by the Company. The Company also has a non-qualified supplemental plan for certain executives and a non-qualified retiree only plan for certain early retirement benefits. The net pension costs for these plans for 1999, 1998 and 1997 were ($7,960,000), ($5,138,000), and ($4,626,000), respectively.

The Company's funding policy for the qualified plan is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the plan. In 1997, the Company contributed $2.7 million for 1996 funding requirements and $2.5 million for 1997 funding requirements. In 1998, the Company contributed $2.6 million for 1998 funding requirements. The Company did not make a contribution in 1999. The Company has established a supplemental retirement benefit trust and through this trust purchased life insurance policies on the officers of the Company to fund the future liability under the supplemental plan. The cash surrender value of these policies is shown as an investment on the Company's Consolidated Balance Sheet.

In addition to providing pension benefits, the Company also provides other postretirement benefits (OPEB), consisting principally of health care and life insurance benefits, for retired employees and their dependents. Employees whose sum of age and years of service at time of retirement is equal to or greater than 85 (or who are 62 with at least 20 years of service) are eligible for benefits partially subsidized by the Company. The amount of benefits subsidized by the Company is determined by age and years of service at retirement.

For funding purposes, the Company established a Voluntary Employees' Benefit Association Trust (VEBA) to fund OPEB for the Company's union employees. Approximately 47% of the Company's employees are represented by Local 470-1, Utility Workers Union of America, AFL-CIO, for collective bargaining purposes. The Company established a 401(h) account in connection with the qualified pension plan to fund OPEB for the Company's non-union employees who retire on or after January 1, 1994. The funding policy assumes contributions to these trust funds to be the total OPEB expense calculated under SFAS No. 106, adjusted to reflect a share of amounts expensed as a result of voluntary early retirement programs minus pay-as-you-go benefit payments for pre-January 1, 1994 non-union retirees, allocated in a manner that minimizes current income tax liability, without exceeding maximum tax deductible limits. In accordance with this policy, the Company did not make contributions to the union VEBA in 1999, 1998 and 1997. The Company did not make a contribution to the 401(h) account in 1999 and contributed $0.9 million and $1.7 million to the 401(h) account in 1998 and 1997, respectively. Plan assets for both the union VEBA and 401(h) account consist primarily of equity and fixed-income securities.

(H) Pension and Other Benefits (continued)

The following table represents the plans' beginning benefit obligation balance reconciled to the ending benefit obligation balance, beginning fair value of plan assets balance reconciled to the ending fair value of plan assets balance and the respective funded status reconciled to the Consolidated Balance Sheet.

	Pension Benefits		Other Post-retirement Benefits	
(In Thousands) At December 31,	1999	1998	1999	1998
CHANGE IN BENEFIT OBLIGATION				
Benefit obligation at beginning of year	$280,746	$259,545	$40,229	$35,112
Service Cost	5,334	4,389	549	1,078
Interest cost	17,470	17,828	2,276	2,576
Amendments	994	–	1,364	–
Actuarial (gain) loss	(34,672)	14,064	(9,322)	4,002
Benefits paid (including expenses)	(18,979)	(15,080)	(1,935)	(2,539)
Acquisition/(Divestiture)	(18,500)	–	(1,570)	–
Benefit obligation at end of year	$232,393	$280,746	$31,591	$40,229
CHANGE IN PLAN ASSETS				
Fair value of plan assets at beginning of year	$268,684	$243,739	$23,203	$21,168
Actual return on plan assets	39,757	38,224	555	2,491
Employer contributions	2,525	2,914	208	910
Benefits paid (including expenses)	(18,979)	(16,193)	(1,935)	(1,366)
Acquisition/(Divestiture)	(14,000)	–	(1,350)	–
Fair value of plan assets at end of year	$277,987	$268,684	$20,681	$23,203
Funded Status at December 31:				
Projected benefits (less than) greater than plan assets	$ (45,594)	$ 12,062	$10,910	$17,026
Unrecognized prior service cost	(3,731)	(3,878)	(291)	946
Unrecognized transition asset	5,552	7,274	(13,435)	(16,368)
Unrecognized net gain (loss) from past experience	62,799	15,639	7,674	1,241
Accrued benefit obligation	$ 19,026	$ 31,097	$ 4,858	$ 2,845

	Pension Benefits		Other Post-retirement Benefits	
At December 31,	1999	1998	1999	1998
The following actuarial assumptions were used in calculating the benefit obligations at December 31:				
Discount rate	7.50%	6.75%	7.50%	6.75%
Average wage increase	4.50%	4.50%	4.50%	4.50%
Health care cost trend rate	N/A	N/A	5.50%	5.50%

The components of net periodic benefit cost are:

(In Thousands) For the Year Ended December 31,	Pension Benefits 1999	Pension Benefits 1998	Other Post-retirement Benefits 1999	Other Post-retirement Benefits 1998
Components of net periodic benefit cost:				
Service cost	$ 5,334	$ 4,389	$ 549	$1,078
Interest cost	17,470	17,828	2,276	2,576
Expected return on plan assets	(28,677)	(25,934)	(2,463)	(2,249)
Amortization of:				
Prior service costs	537	406	11	(71)
Transition obligation (asset)	(1,097)	(1,095)	1,169	1,169
Actuarial (gain) loss	(1,527)	(1,132)	(801)	(361)
Settlements (curtailments)	–	400	–	–
Net periodic benefit cost	($7,960)	($5,138)	$ 741	$2,142

For the Year Ended December 31,	Pension Benefits 1999	Pension Benefits 1998	Other Post-retirement Benefits 1999	Other Post-retirement Benefits 1998
The following actuarial assumptions were used in calculating net periodic benefit cost:				
Discount rate	6.75%	7.25%	6.75%	7.25%
Average wage increase	4.50%	4.50%	4.50%	4.50%
Return on plan assets	11.00%	11.00%	11.00%	11.00%
Health care cost trend rate	N/A	N/A	5.50%	5.50%

A one percentage point change in the assumed health care cost trend rate would have the following effects:

(In Thousands)	1% Increase	1% Decrease
Aggregate service and interest cost components	$ 346	$ (344)
Accumulated postretirement benefit obligation	$3,316	$(3,608)

The Company has an Employee Savings Plan (401(k) Plan) in which substantially all employees are eligible to participate. The 401(k) Plan enables employees to defer receipt of up to 15% of their compensation and to invest such funds in a number of investment alternatives. The Company also has an Employee Stock Ownership Plan (ESOP) for substantially all its employees. The Company makes matching contributions to the ESOP, in the form of Company common stock, based on each employee's salary deferrals in the 401(k) Plan. The matching contribution currently equals fifty cents for each dollar of the employee's compensation deferred, but is not more than three and three-eighths percent of the employee's annual salary. The Company's matching contributions to the ESOP during 1999, 1998 and 1997 were $1.5 million, $1.7 million and $1.7 million, respectively.

The Company pays dividends on the shares of stock in the ESOP to the participant and the Company receives a tax deduction for the dividends paid. The Company also makes contributions to the ESOP equal to 25% of the dividends paid to each participant. The Company's annual contributions during 1999, 1998 and 1997 were $319,000, $270,000 and $417,000, respectively.

(I) Jointly Owned Plant

At December 31, 1999, the Company had the following interests in jointly owned plants:

(In Millions Except Share Amounts)	Ownership/ Leasehold Share	Plant Investment (1)	Accumulated Depreciation
Seabrook Unit 1	17.5 %	$658	$164
Millstone Unit 3	3.685	136	66

(1) Of the plant investment amounts, $456 million for Seabrook Unit 1 and $62 million for Millstone Unit 3 are reflected on the consolidated balance sheet as regulatory assets.

The Company's share of the operating costs of jointly owned plants is included in the appropriate expense captions in the Consolidated Statement of Income.

(J) Unamortized Cancelled Nuclear Project

From December 1984 through December 1992, the Company had been recovering its investment in Seabrook Unit 2, a partially constructed nuclear generating unit that was cancelled in 1984, over a regulatory approved ten-year period without a return on its unamortized investment. In the Company's 1992 rate decision, the DPUC adopted a proposal by the Company to write off its remaining investment in Seabrook Unit 2, beginning January 1, 1993, over a 24-year period, corresponding with the flowback of certain Connecticut Corporation Business Tax (CCBT) credits. Such decision will allow the Company to retain the Seabrook Unit 2/CCBT amounts for ratemaking purposes, with the accumulated CCBT credits not deducted from rate base during the 24-year period of amortization in recognition of a longer period of time for amortization of the Seabrook Unit 2 balance. As a result of reducing its remaining unamortized investment in Seabrook Unit 2 with proceeds from the sale of certain Seabrook Unit 2 equipment, the Company expects to completely amortize its unamortized investment in the year 2007.

(K) Fuel Financing Obligations and Other Lease Obligations

The Company had a Fossil Fuel Supply Agreement with a financial institution providing for the financing of up to $37.5 million of fossil fuel purchases. On April 16, 1999, the Company sold all of its operating non-nuclear generation facilities to an unaffiliated entity. See Note (C), "Rate-Related Regulatory Proceedings." As a result, the Company no longer has a need to acquire fossil fuel. The Company and the financial institution agreed to terminate this agreement as of May 31,1999 at no cost to the Company.

The Company also has lease arrangements for data processing equipment, office equipment, vehicles and office space, including the lease of a distribution service facility, which is recognized as a capital lease. The gross amount of assets recorded under capital leases and the related obligations of those leases as of December 31, 1999 are recorded on the balance sheet.

Future minimum lease payments under capital leases, excluding the Seabrook sale/leaseback transaction, which is being treated as a long-term financing, are estimated to be as follows:

(In Thousands)	
2000	$ 1,696
2001	1,696
2002	1,696
2003	1,696
2004	16,000
After 2004	–
Total minimum capital lease payments	22,784
Less: Amount representing interest	6,278
Present value of minimum capital lease payments	$16,506

Capitalization of leases has no impact on income, since the sum of the amortization of a leased asset and the interest on the lease obligation equals the rental expense allowed for ratemaking purposes.

Operating leases, which are charged to operating expense, consist principally of a large number of small, relatively short-term, renewable agreements for a wide variety of equipment. In addition, the Company has an operating lease for its corporate headquarters. Future minimum lease payments under this lease are estimated to be as follows:

(In Thousands)	
2000	$ 6,524
2001	6,837
2002	8,168
2003	9,125
2004	9,242
2005-2012	81,966
Total	$121,862

Rental payments charged to operating expenses in 1999, 1998 and 1997, including rental payments for its corporate headquarters, were $11.0 million, $11.7 million and $12.2 million, respectively.

(L) Commitments and Contingencies

CAPITAL EXPENDITURE PROGRAM (UNAUDITED) The Company's 2000-2004 estimated capital expenditure program, excluding allowance for funds used during construction, is presently budgeted as follows:

(In Thousands)	2000	2001	2002	2003	2004	Total
Nuclear Generation (1)	$ 3,113	$ 3,591	$ –	$ –	$ –	$ 6,704
Distribution and Transmission	46,652	25,393	16,068	13,450	30,850	132,413
Subtotal	49,765	28,984	16,068	13,450	30,850	139,117
Nuclear Fuel	8,317	7,090	2,880	8,394	–	26,681
Total Utility Expenditures	58,082	36,074	18,948	21,844	30,850	165,798
Total Non-Regulated Business Expenditures	4,294	5,364	3,864	4,038	4,167	21,727
Total	$62,376	$41,438	$22,812	$25,882	$35,017	$187,525

(1) The Connecticut Restructuring Act and decisions of the Connecticut DPUC do not allow for the capitalization of nuclear generation costs, other than for nuclear fuel, beyond 2001.

NUCLEAR INSURANCE CONTINGENCIES The Price-Anderson Act, currently extended through August 1, 2002, limits public liability resulting from a single incident at a nuclear power plant. The first $200 million of liability coverage is provided by purchasing the maximum amount of commercially available insurance. Additional liability coverage will be provided by an assessment of up to $88.1 million per incident, levied on each of the nuclear units licensed to operate in the United States, subject to a maximum assessment of $10 million per incident per nuclear unit in any year. In addition, if the sum of all public liability claims and legal costs resulting from any nuclear incident exceeds the maximum amount of financial protection, each reactor operator can be assessed an additional 5% of $88.1 million, or $4.4 million. The maximum assessment is adjusted at least every five years to reflect the impact of inflation. With respect to each of the two operating nuclear generating units in which the Company has an interest, the Company will be obligated to pay its ownership and/or leasehold share of any statutory assessment resulting from a nuclear incident at any nuclear generating unit. Based on its interests in these nuclear generating units, the Company estimates its maximum liability would be $18.6 million per incident. However, any assessment would be limited to $2.1 million per incident per year.

(L) Commitments and Contingencies (continued)

The NRC requires each operating nuclear generating unit to obtain property insurance coverage in a minimum amount of $1.06 billion and to establish a system of prioritized use of the insurance proceeds in the event of a nuclear incident. The system requires that the first $1.06 billion of insurance proceeds be used to stabilize the nuclear reactor to prevent any significant risk to public health and safety and then for decontamination and cleanup operations. Only following completion of these tasks would the balance, if any, of the segregated insurance proceeds become available to the unit's owners. For each of the two operating nuclear generating units in which the Company has an interest, the Company is required to pay its ownership and/or leasehold share of the cost of purchasing such insurance. Although each of these units has purchased $2.75 billion of property insurance coverage, representing the limits of coverage currently available from conventional nuclear insurance pools, the cost of a nuclear incident could exceed available insurance proceeds. Under those circumstances, the nuclear insurance pools that provide this coverage may levy assessments against the insured owner companies if pool losses exceed the accumulated funds available to the pool. The maximum potential assessments against the Company with respect to losses occurring during current policy years are approximately $3.1 million.

OTHER COMMITMENTS AND CONTINGENCIES

• CONNECTICUT YANKEE On December 4, 1996, the Board of Directors of the Connecticut Yankee Atomic Power Company (Connecticut Yankee) voted unanimously to retire the Connecticut Yankee nuclear plant (the Connecticut Yankee Unit) from commercial operation. The Company has a 9.5% stock ownership share in Connecticut Yankee. The power purchase contract under which the Company has purchased its 9.5% entitlement to the Connecticut Yankee Unit's power output permits Connecticut Yankee to recover 9.5% of all of its costs from the Company. In December of 1996, Connecticut Yankee filed decommissioning cost estimates and amendments to the power contracts with its owners with the Federal Energy Regulatory Commission (FERC). Based on regulatory precedent, this filing seeks confirmation that Connecticut Yankee will continue to collect from its owners its decommissioning costs, the unrecovered investment in the Connecticut Yankee Unit and other costs associated with the permanent shutdown of the Connecticut Yankee Unit. On August 31, 1998, a FERC Administrative Law Judge (ALJ) released an initial decision regarding Connecticut Yankee's December 1996 filing. The initial decision contains provisions that would allow Connecticut Yankee to recover, through the power contracts with its owners, the balance of its net unamortized investment in the Connecticut Yankee Unit, but would disallow recovery of a portion of the return on Connecticut Yankee's investment in the unit. The ALJ's decision also states that decommissioning cost collections by Connecticut Yankee, through the power contracts, should continue to be based on a previously-approved estimate until a new, more reliable estimate has been prepared and tested. During October of 1998, Connecticut Yankee and its owners filed briefs setting forth exceptions to the ALJ's initial decision. If this initial decision is upheld by the FERC, Connecticut Yankee could be required to write off a portion of the regulatory asset on its Balance Sheet associated with the retirement of the Connecticut Yankee Unit. In this event, however, the Company would not be required to record any write-off on account of its 9.5% ownership share in Connecticut Yankee, because the Company has recorded its regulatory asset associated with the retirement of the Connecticut Yankee Unit net of any return on investment. The Company cannot predict, at this time, the outcome of the FERC proceeding. However, the Company will continue to support Connecticut Yankee's efforts to contest the ALJ's initial decision.

The Company's estimate of its remaining share of Connecticut Yankee costs, including decommissioning, less return of investment (approximately $10.0 million) and return on investment (approximately $3.8 million) at December 31, 1999, is approximately $27.1 million. This estimate, which is subject to ongoing review and revision, has been recorded by the Company as an obligation and a regulatory asset on the Consolidated Balance Sheet.

• HYDRO-QUEBEC The Company is a participant in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. Phase I of this facility, which became operational in 1986 and in which the Company has a 5.45% participating share, has a 690 megawatt equivalent capacity value; and Phase II, in which the Company has a 5.45% participating share, increased the equivalent capacity value of the intertie from 690 megawatts to a maximum of 2000 megawatts in 1991. The Company is obligated to furnish a guarantee for its participating share of the debt financing for the Phase II facility. As of December 31, 1999, the Company's guarantee liability for this debt was approximately $6.2 million.

• ENVIRONMENTAL CONCERNS In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water quality, hazardous waste handling and disposal, toxic substances, and electric and magnetic fields, the Company may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, and it may incur additional operating expenses. Litigation expenditures may also increase as a result of scientific investigations, and speculation and debate, concerning the possibility of harmful health effects of electric and magnetic fields. The total amount of these expenditures is not now determinable.

• SITE DECONTAMINATION, DEMOLITION AND REMEDIATION COSTS The Company has estimated that the total cost of decontaminating and demolishing its Steel Point Station and completing requisite environmental remediation of the site will be approximately $11.3 million, of which approximately $8.4 million had been incurred as of December 31, 1999, and that the value of the property following remediation will not exceed $6.0 million. As a result of a 1992 DPUC retail rate decision, beginning January 1, 1993, the Company has been recovering through retail rates $1.075 million of the remediation costs per year. The remediation costs, property value and recovery from customers will be subject to true-up in the Company's next retail rate proceeding based on actual remediation costs and actual gain on the Company's disposition of the property.

The Company is presently remediating an area of PCB contamination at a site, bordering the Mill River in New Haven, that contains transmission facilities and the deactivated English Station generation facilities. In addition, the Company is currently replacing the bulkhead that surrounds this site, at an estimated cost of $13.5 million. Of this amount, $4.2 million represents the portion of the costs to protect the Company's transmission facilities and will be capitalized as plant in service. The remaining estimated cost of $9.3 million was expensed in 1999.

As described at Note (C), "Rate-Related Regulatory Proceedings," the Company has sold its Bridgeport Harbor Station and New Haven Harbor Station generating plants in compliance with Connecticut's electric utility industry restructuring legislation. Environmental assessments performed in connection with the marketing of these plants indicate that substantial remediation expenditures will be required in order to bring the plant sites into compliance with applicable Connecticut minimum standards following their sale. The purchaser of the plants has agreed to undertake and pay for the major portion of this remediation. However, the Company will be responsible for remediation of the portions of the plant sites that will be retained by it.

(M) Nuclear Fuel Disposal and Nuclear Plant Decommissioning

Costs associated with nuclear plant operations include amounts for disposal of nuclear wastes, including spent fuel, and for the ultimate decommissioning of the plants. Under the Nuclear Waste Policy Act of 1982, the federal Department of Energy (DOE) is required to design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel. The Act requires the DOE to provide for the disposal of spent nuclear fuel and high level radioactive waste from commercial nuclear plants through contracts with the owners and generators of such waste; and the DOE has established disposal fees that are being paid

(M) Nuclear Fuel Disposal and Nuclear Plant Decommissioning (continued)

to the federal government by electric utilities owning or operating nuclear generating units. In return for payment of the prescribed fees, the federal government was required to take title to and dispose of the utilities' high level wastes and spent nuclear fuel beginning no later than January 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010, and possibly not earlier than 2013, and that, absent a repository, the DOE has no statutory obligation to begin taking high level wastes and spent nuclear fuel for disposal by January 1998. However, numerous utilities and states have obtained a judicial declaration that the DOE has a statutory responsibility to take title to and dispose of high level wastes and spent nuclear fuel beginning in January 1998, and that the contracts between the DOE and the plant owners and generators of such waste will provide a potentially adequate remedy to owners and generators in monetary damages for breach of the contracts. The DOE is contesting these judicial declarations; and it is unclear at this time whether the United States Congress will enact legislation to address spent fuel/high level waste disposal issues.

Until the federal government begins receiving such materials, nuclear generating units will need to retain high level wastes and spent nuclear fuel on-site or make other provisions for their storage. Storage facilities for the Connecticut Yankee Unit are deemed adequate, and storage facilities for Millstone Unit 3 are expected to be adequate for the projected life of the unit. Storage facilities for Seabrook Unit 1 are expected to be adequate until at least 2010. Fuel consolidation and compaction technologies are being considered for Seabrook Unit 1 and may provide adequate storage capability for the projected life of the unit. In addition, other licensed technologies, such as dry storage casks, may satisfy spent nuclear fuel storage requirements.

Disposal costs for low-level radioactive wastes (LLW) that result from operation or decommissioning of nuclear generating units decreased in 1999, as a result of negotiations between the generators of such wastes and the owners of licensed disposal facilities. Currently, the Chem Nuclear LLW facility at Barnwell, South Carolina, is open to the Connecticut Yankee Unit, Millstone Unit 3, and Seabrook Unit 1 for disposal of LLW. The Envirocare LLW facility at Clive, Utah, is also open to these generating units for portions of their LLW. All three units have contracts in place for LLW disposal at these disposal facilities.

Because access to a LLW disposal facility may be lost at any time, Millstone Unit 3 and Seabrook Unit 1 have storage plans that will allow on-site retention of LLW for at least five years in the event that disposal is interrupted. The Connecticut Yankee Unit, which has been retired from commercial operation, has a similar storage program, although disposal of its LLW will take place in connection with its decommissioning.

The Company cannot predict whether or when a LLW disposal site will be designated in Connecticut. The State of New Hampshire has not met deadlines for compliance with the Low-Level Radioactive Waste Policy Act and has stated that the state is unsuitable for a LLW disposal facility. Both Connecticut and New Hampshire are also pursuing other options for out-of-state disposal of LLW. Connecticut and New Jersey, who have formed the Northeast Interstate LLW Compact, are negotiating terms for South Carolina to join them, which would increase the likelihood that the Connecticut Yankee Unit and Millstone Unit 3 will have access to the Chem Nuclear LLW facility at Barnwell, South Carolina, through the end of their decommissioning.

NRC licensing requirements and restrictions are also applicable to the decommissioning of nuclear generating units at the end of their service lives, and the NRC has adopted comprehensive regulations concerning decommissioning planning, timing, funding and environmental reviews. The Company and the other owners of the nuclear generating units in which the Company has interests estimate decommissioning costs for the units and attempt to recover sufficient amounts through their allowed electric rates, together with earnings on the investment of funds so recovered, to cover expected decommissioning costs. Changes in NRC requirements or technology, as well as inflation, can increase estimated decommissioning costs.

New Hampshire has enacted a law requiring the creation of a government-managed fund to finance the decommissioning of nuclear generating units in that state. The New Hampshire Nuclear Decommissioning Financing Committee (NDFC) has established $565 million (in 2000 dollars) as the decommissioning cost estimate for Seabrook Unit 1, of which the Company's share would be approximately $99 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 36-year energy producing life. Monthly decommissioning payments are being made to the state-managed decommissioning trust fund. The Company's share of the decommissioning payments made during 1999 was $3.3 million. The Company's share of the fund at December 31, 1999 was approximately $20.5 million.

Connecticut has enacted a law requiring the operators of nuclear generating units to file periodically with the DPUC their plans for financing the decommissioning of the units in that state. The current decommissioning cost estimate for Millstone Unit 3 is $619 million (in 2000 dollars), of which the Company's share would be approximately $23 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 40-year energy producing life. Monthly decommissioning payments, based on these cost estimates, are being made to a decommissioning trust fund managed by Northeast Utilities (NU). The Company's share of the Millstone Unit 3 decommissioning payments made during 1999 was $0.7 million. The Company's share of the fund at December 31, 1999 was approximately $7.8 million. The current decommissioning cost estimate for the Connecticut Yankee Unit, assuming the prompt removal and dismantling of the unit, is $498 million, of which the Company's share would be $47 million. Through December 31, 1999, $169 million has been expended for decommissioning. The projected remaining decommissioning cost is $329 million, of which the Company's share would be $31 million. The decommissioning trust fund for the Connecticut Yankee Unit is also managed by NU. For the Company's 9.5% equity ownership in Connecticut Yankee, decommissioning costs of $2.4 million were funded by the Company during 1999, and the Company's share of the fund at December 31, 1999 was $17.7 million.

The Financial Accounting Standards Board (FASB) expects to issue a revised exposure draft related to the accounting for the closure and removal costs of long-lived assets, including nuclear plant decommissioning. If the proposed accounting standard were adopted, it may result in higher annual provisions for decommissioning to be recognized earlier in the operating life of nuclear units and an accelerated recognition of the decommissioning obligation. The FASB will be deliberating this issue, and the resulting final pronouncement is not expected to be effective prior to 2002.

(N) Fair Value of Financial Instruments

The estimated fair values of the Company's financial instruments are as follows:

(In Thousands)	1999		1998	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Unrestricted cash and temporary cash investments	$ 39,099	$ 39,099	$ 97,689	$ 97,689
Long-term debt [1][2][3]	$420,217	$399,767	$606,342	$611,524

(1) Excludes the obligation under the Seabrook Unit 1 sale/leaseback agreement.

(2) The fair market value of the Company's long-term debt is estimated by brokers based on market conditions at December 31, 1999 and 1998, respectively.

(3) See Note (B), "Capitalization – Long-Term Debt."

(O) Quarterly Financial Data (Unaudited)

Selected quarterly financial data for 1999 and 1998 are set forth below:

(In Thousands Except Per Share Amount)

Quarter	Operating Revenues	Operating Income	Net Income	Earnings per Share of Common Stock (1) Basic	Diluted
1999					
First Quarter	$168,667	$23,207	$ 9,901	$ .70	$ .70
Second Quarter	164,533	25,193	13,986	.99	.99
Third Quarter	199,071	34,183	24,997	1.78	1.78
Fourth Quarter	147,704	10,972	3,340	.24	.24
1998					
First Quarter	$162,474	$22,677	$ 8,962	$0.64	$0.64
Second-Originally Reported	$159,792	$21,174	$ 5,497	$0.39	$0.39
Provision – APS accounts receivable	–	–	2,882	0.21	0.21
Second-As Restated	$159,792	$21,174	$ 8,379	$0.60	$0.60
Third Quarter	$198,601	$37,462	$26,236	$1.87	$1.87
Fourth Quarter (2)	$165,324	$15,013	$ 1,495	$0.10	$0.10

(1) Based on weighted average number of shares outstanding each quarter.

(2) Operating income, net income and earnings per share for the fourth quarter of 1998 included an after-tax charge of $8.3 million, associated with a property tax settlement.

(P) Segment Information

The Company has one reportable operating segment, that of regulated generation, distribution and sale of electricity. The accounting policies used for that segment do not differ from those used for nonreportable operating segments. Revenues from inter-segment transactions are not material and all of the Company's revenues are derived in the United States.

The revenues from external customers, interest income, interest expense and depreciation charges of the one reportable segment are identical to the amounts shown on the Consolidated Statement of Income for each year presented. Income before taxes of the reportable segment is not materially different from that of the Company as a whole.

The following table reconciles the total assets of the reportable segment with the total assets shown on the Consolidated Balance Sheet at December 31:

(In Thousands)	1999	1998
Total Assets – Regulated Utility	$1,809,451	$1,943,328
Total Assets – Unregulated Subsidiaries	194,642	83,306
Total Assets – Elimination	(205,883)	(85,474)
Total Consolidated Assets	$1,798,210	$1,941,160

(Q) Restatement of Financial Results

AMERICAN PAYMENT SYSTEMS, INC. (APS) RESTATEMENTS During the third quarter of 1999, the Company has restated its financial statements for 1998, 1997 and 1996 for matters related to the timing of American Payment Systems ("APS") agency collection reserves, for certain line loss factors that affect the calculation of unbilled revenues and for cash, accounts receivable and accounts payable amounts related to APS's collection agent network. The Company had consultations with the staff of the Securities and Exchange Commission and its independent accountants in determining these restated amounts.

During 1997 and 1996, APS agent bank accounts were not fully reconciled at the time APS balance sheet items were prepared to allow for the identification, measurement and enforcement of material claims for recovery from APS agents for defalcated amounts or from APS customers for checks returned by banks due to insufficient funds. As a result, losses associated with collection agent errors and defaults went undetected for extended periods of time. In the second quarter of 1998, the Company performed a review of the accounting records at APS and identified significantly past due agent collections of $4.9 million ($2.8 million, after-tax) that represented agent deposit shortfalls and uncollectible agent check deposits. Pursuant to the result of this review, APS increased its provision against their receivable balance by $4.9 million ($2.8 million, after-tax) in the second quarter of 1998. The Company applied similar procedures during 1996 and, based on the results, recorded a $4.5 million ($2.6 million, after-tax) increase in its provision in the fourth quarter of 1996. Due to the fact that these adjustments related to losses incurred in both current and prior periods, the Company has restated the effects of these adjustments back to the periods in which the losses occurred as shown below. The impact of the adjustments described above was to reduce retained earnings as of January 1, 1998 by $2.8 million.

The restatement of cash, accounts receivable and accounts payable amounts related to APS's collection agent network was recorded so as to include on the Company's consolidated balance sheet amounts that had previously been recorded on a net basis.

UNBILLED REVENUE RESTATEMENT During the third quarter of 1999, the Company reviewed an adjustment of $2.7 million ($1.6 million, after-tax) made to retail operating revenues in the fourth quarter of 1997 related to the reversal of prior period overestimates of transmission line losses. The Company uses an estimated line loss factor, based upon a 24 month-moving historical line loss factor, to calculate the amount of revenue from electricity sales that is unbilled during the period and therefore should be accrued. This loss factor is applied to the known amount of electricity delivered to the Company's transmission grid from internal and external sources. Historically, this methodology provided a reasonable estimate of the amount of unbilled revenue.

Beginning in the first quarter of 1996, the outages of four nuclear generating units resulted in the Company purchasing power from other sources. The electricity from other sources followed different transmission paths and exhibited different line loss characteristics than the electricity generated by the nuclear generating units. During this period of time, the Company continued to utilize the 24 month-moving average loss factor in order to smooth the impact of changes in the line loss factors in the calculation of unbilled revenue amounts.

Based upon a review of the actual New England Power Pool line loss factors during this period and the pattern of when they occurred, the Company has restated the $1.2 million ($0.7 million, after-tax) of the adjustment made to retail operating revenues, originally recorded in the fourth quarter of 1997, to 1996.

(Q) Restatement of Financial Results (continued)

The following tables summarize the restatements that the Company has made on net income, earnings per share and retained earnings.

Increase (decrease) in net income:

(In Thousands) For the year ended December 31,	1998	1997
DESCRIPTION		
1998 APS charge	$ 2,882	$ (1,643)
1997 unbilled revenues	–	(691)
Net increase (decrease) to net income	2,882	(2,334)
Net income applicable to common shareholders, as originally reported	42,010	45,634
Net income applicable to common shareholders, as restated	$ 44,892	$ 43,300

For the year ended December 31,	1998	1997
DESCRIPTION		
Earnings per share, as originally reported		
– Basic	$ 3.00	$ 3.27
– Diluted	$ 3.00	$ 3.26
Earnings per share, as restated		
– Basic	$ 3.20	$ 3.10
– Diluted	$ 3.20	$ 3.09

(In Thousands) As of December 31,	1998	1997
DESCRIPTION		
Retained earnings, as originally reported	$163,847	$162,226
Net effect of restatements, described above	–	(2,882)
Retained earnings, as restated	$163,847	$159,344

Included in restricted cash at December 31, 1998 is $23,056, representing collections by APS agents that are held in APS agent accounts prior to transmittal to the respective APS customers. In addition, included in other accounts receivable at December 31, 1998 is $26,768, representing collections by APS agents not yet deposited into APS bank accounts. A corresponding accounts payable has been recorded to reflect the portions of these collections owed to APS customers, as well as the amount of restricted cash presented above. The Company had previously presented its consolidated balance sheet net of these accounts receivable and accounts payable amounts.

The following table summarizes the effect of the restatements described above to restricted cash, other accounts receivable, and accounts payable – APS customers:

(In Thousands) As of December 31,	1998
Restricted cash, as originally reported	$ –
Effect of restatement, described above	23,056
Restricted cash, as restated	$23,056
Other accounts receivable, as originally reported (1)	$37,472
Effect of restatement, described above	
Additional accounts receivable for APS agents	26,768
Additional APS agent collection reserves	–
Other accounts receivable, as restated	$64,240
Accounts payable – APS customers, as originally reported	$ –
Accounts payable – APS customers reclassed from accounts payable	4,691
Effect of restatement, described above	
Restricted cash	23,056
Additional amounts owed to APS customers	26,768
Accounts payable – APS customers, as restated	$54,515

(1) Includes accounts receivable from APS agents originally included in other accounts receivable of $4,691,000 as of December 31, 1998.

Market for the Company's Common Equity and Related Stockholder Matters

The Company's Common Stock is traded on the New York Stock Exchange, where the high and low sale prices during 1999 and 1998 were as follows:

	1999 Sale Price		1998 Sale Price	
	High	Low	High	Low
First Quarter	52 11/16	41 7/8	48 9/16	42 5/8
Second Quarter	44 11/16	39 5/16	51 15/16	46 15/16
Third Quarter	50 11/16	43 1/8	53 9/16	49
Fourth Quarter	53 3/16	47 15/16	53 3/4	48 1/16

The Company has paid quarterly dividends on its Common Stock since 1900. The quarterly dividends declared in 1998 and 1999 were at a rate of 72 cents per share.

The indenture under which $200 million principal amount of Notes are issued places limitations on the payment of cash dividends on common stock and on the purchase or redemption of common stock. Retained earnings in the amount of $117.3 million were free from such limitations at December 31, 1999.

As of December 31, 1999, there were 13,664 Common Stock shareowners of record.

Selected Financial Data

	1999	1998	1997
FINANCIAL RESULTS OF OPERATION (THOUSANDS)			
Sales of Electricity			
Retail			
Residential	$ 271,605	$ 262,974	$ 259,325
Commercial	256,246	254,765	248,490
Industrial	100,437	102,201	102,763
Other	11,308	11,667	11,755
TOTAL RETAIL	639,596	631,607	622,333
Wholesale (1)	24,334	44,948	82,871
Other operating revenues	16,045	9,636	3,825
TOTAL OPERATING REVENUES	679,975	686,191	709,029
Fuel and interchange energy – net			
Retail – own load	134,851	116,769	109,542
Wholesale	24,552	34,775	73,124
Capacity purchased – net	33,873	34,515	39,976
Depreciation	57,351	82,809 (3)	74,618 (3)
Other amortization, principally deferred return, cancelled plant and regulatory tax assets	36,393	13,758	13,758
Other operating expenses, excluding tax expense	185,696	188,946	200,803
Gross earnings tax	24,518	24,039	23,571
Other non-income taxes	22,622	40,635 (4)	28,922
TOTAL OPERATING EXPENSES, EXCLUDING INCOME TAXES	519,856	536,246	564,314
Deferred return – Seabrook Unit 1	0	0	0
AFUDC	2,235	468	1,575
Other non-operating income (loss)	(838)	1,097 (5)	1,361
Interest expense			
Long-term debt – net	35,260	42,836	56,158
Dividend requirement of mandatory redeemable securities	4,813	4,813	4,813
Other	7,319	9,018	6,068
TOTAL	47,392	56,667	67,039
Income tax expense			
Operating income tax	66,564	53,619	40,833 (6)
Non-operating income tax	(4,664)	(3,848)	(3,678)
TOTAL	61,900	49,771	37,155
Income before cumulative effect of accounting change	52,224	45,072	43,457
Cumulative effect of change in accounting – net of tax	0	0	0
Net income	52,224	45,072	43,457
Premium (Discount) on preferred stock redemption	53	(21)	(48)
Preferred and preference stock dividends	66	201	205
Income applicable to common stock	$ 52,105	$ 44,892	$ 43,300
OPERATING INCOME	$ 93,555	$ 96,326	$ 103,882
FINANCIAL CONDITION (THOUSANDS)			
Plant in service – net	$ 474,656 (12)	$1,172,555	$1,222,174
Construction work in progress	25,708	33,695	25,448
Other property and investments	152,948 (13)	58,047	58,441
Current assets	220,126	305,189	204,474
Deferred charges and regulatory assets	924,772 (12)	371,674	408,993
TOTAL ASSETS	$1,798,210	$1,941,160	$1,919,530
Common stock equity	$ 458,298	$ 445,507	$ 436,081
Preferred, preference stock and company-obligated mandatorily redeemable securities of subsidiaries holding solely parent debentures	50,000	54,299	54,351
Long-term debt excluding current portion	518,228	664,510	644,670
Non-current liabilities (9)	245,268	109,981	119,868
Current portion of long-term debt	25,000	66,202	100,000
Notes payable	17,131	86,892	37,751
Other current liabilities (9)	166,213	172,830	175,340
Deferred income tax liabilities and other	318,072	340,939	351,469
TOTAL CAPITALIZATION & LIABILITIES	$1,798,210	$1,941,160	$1,919,530

(1) Operating Revenues, for years prior to 1992, include wholesale power exchange contract sales that were reclassified from Fuel and Capacity expenses in accordance with Federal Energy Regulatory Commission requirements.
(2) Includes reclassification of certain Commercial and Industrial customers.
(3) Includes the before-tax effect of charges for additional amortization of conservation & load management costs: $13.1 million in 1998 and $6.6 million in 1997.
(4) Includes the effect of charges of $14.0 million, before-tax, associated with property tax settlement.
(5) Includes the before-tax effect of charges for losses associated with unregulated subsidiaries: $2.8 million in 1997 and $5.8 million in 1996.
(6) Includes the effect of credits of $6.7 million to provide tax provision for fossil generation decommissioning.

1996	1995	1994	1993	1992	1991	1990
$ 266,068	$ 260,694	$ 252,386	$ 238,185	$ 226,455	$ 226,751	$ 211,891
264,111	259,715	250,771 (2)	256,559	253,456 (2)	255,782	234,704
109,032	106,963	104,242 (2)	97,466	97,010 (2)	91,895	94,526
11,903	11,736	11,469	11,349	11,065	10,886	10,536
651,114	639,108	618,868	603,559	587,986	585,314	551,657
72,844	48,232	34,927	45,931	75,484	84,236	85,657
3,300	3,109	2,953	3,533	3,855	3,821	3,332
727,258	690,449	656,748	653,023	667,325	673,371	640,646
95,359	96,538	99,589	98,694	108,084	123,010	119,285
65,158	41,631	27,765	39,356	55,169	61,858	69,117
46,830	47,420	44,769	47,424	43,560	44,668	42,827
65,921	61,426	58,165	56,287	50,706	48,181	36,526
13,758	13,758	1,172	1,780	10,415	10,415	4,173
219,630 (7)	183,749	193,098	203,427 (10)	183,426	178,912	176,419
26,804	27,379	27,403	27,955	27,362	27,223	25,595
30,382	31,564	32,458	29,977	31,869	28,673	24,648
563,842	503,465	484,419	504,900	510,591	522,940	498,590
0	0	0	7,497	15,959	17,970	21,503
2,375	2,762	3,463	4,067	3,232	5,190	3,443
(8,445) (5)	(5,068)	(1,907)	71	18,545	2,697	22,654
65,046	63,431	73,772	80,030	88,666	90,296	94,056
4,813	3,583	0	0	0	0	0
4,721	12,841	10,301	12,260	12,882	9,847	15,468
74,580	79,855	84,073	92,290	101,548	100,143	109,524
53,590	59,828	44,937	33,309	48,712	47,231	43,493
(9,869)	(4,901)	(3,214)	(6,322)	(12,558)	(19,299)	(17,409)
43,721	54,927	41,723	26,987	36,154	27,932	26,084
39,045	49,896	48,089	40,481	56,768	48,213	54,048
0	0	(1,294)	0	0	7,337	0
39,045 (8)	49,896	46,795	40,481 (11)	56,768	55,550	54,048
(1,840)	(2,183)	0	0	0	0	0
330	1,329	3,323	4,318	4,338	4,530	4,751
$ 40,555	$ 50,750	$ 43,472	$ 36,163	$ 52,430	$ 51,020	$ 49,297
$ 109,826	$ 127,156	$ 127,392	$ 114,814	$ 108,022	$ 103,200	$ 98,563
$1,258,306	$1,277,910	$1,268,145	$1,243,426	$1,224,058	$1,219,871	$1,209,173
40,998	41,817	57,669	77,395	59,809	54,771	50,257
49,091	53,355	53,267	58,096	65,320	79,009	90,006
199,097	136,481	157,309	187,981	247,954	164,839	161,066
449,150	475,258	538,601	567,394	556,493	554,365	553,986
$1,996,642	$1,984,821	$2,074,991	$2,134,292	$2,153,634	$2,072,855	$2,064,488
$ 439,468	$ 439,484	$ 428,028	$ 423,324	$ 422,746	$ 401,771	$ 379,812
54,461	60,539	44,700	60,945	60,945	62,640	69,700
759,680	845,684	708,340	875,268	893,457	909,998	899,993
138,816	65,747	59,458	62,666	44,567	110,217	110,850
69,900	40,800	193,133	143,333	92,833	37,500	41,667
10,965	0	67,000	0	84,099	13,000	15,000
166,138	102,336	122,084	117,343	114,757	114,280	138,173
357,214	430,231	452,248	451,413	440,230	423,449	409,293
$1,996,642	$1,984,821	$2,074,991	$2,134,292	$2,153,634	$2,072,855	$2,064,488

(7) Includes the effect of charges of $23.0 million, before-tax, associated with voluntary early retirement programs.
(8) Includes the effect of charges of $13.4 million, after-tax, associated with voluntary early retirement programs.
(9) Amounts for years prior to 1996 were reclassified in 1996.
(10) Includes the effect of a reorganization charge of $13.6 million, before-tax, associated with a voluntary early retirement program.
(11) Includes the effect of a reorganization charge of $7.8 million, after-tax.
(12) Reflects reclassification of $518.3 million of nuclear assets from plant in service to regulatory asset.
(13) Includes $83.5 million investment in a generation facility as of December 31, 1999.

Selected Financial Data (continued)

	1999	1998	1997
COMMON STOCK DATA			
Average number of shares outstanding	14,052,091	14,017,644	13,975,802
Number of shares outstanding at year-end	14,062,502	14,034,562	13,907,824
Earnings per share (average) – basic	$ 3.71	$ 3.20	$ 3.10
Earnings per share (average) – diluted	$ 3.71	$ 3.20	$ 3.09
Book value per share	$ 32.59	$ 31.74	$ 31.35
Average return on equity			
Total	11.45%	9.44%	10.45%
Utility	14.00%	11.43%	11.54%
Dividends declared per share	$ 2.88	$ 2.88	$ 2.88
Market Price:			
High	$ 53.188	$ 53.750	$ 45.938
Low	$ 39.313	$ 42.625	$ 24.500
Year-end	$ 51.375	$ 51.500	$ 45.938
Net cash provided by operating activities, less dividends ($000's)	$ 57,907	$ 71,566	$ 132,189
Capital expenditures, excluding AFUDC	$ 34,772	$ 38,040	$ 33,436
OTHER FINANCIAL AND STATISTICAL DATA			
Sales by class (MWh's)			
Residential	2,053,927	1,924,724	1,899,284
Commercial	2,388,240	2,324,507	2,248,974
Industrial	1,161,856	1,154,935	1,168,470
Other	48,027	48,166	48,619
Total	5,652,050	5,452,332	5,365,347
Number of retail customers by class (average)			
Residential	282,986	281,591	280,283
Commercial	29,757	29,468	29,228
Industrial	1,746	1,752	1,697
Other	1,185	1,172	1,163
Total	315,674	313,983	312,371
Revenue per kilowatt hour by class (cents)			
Residential	13.22	13.66	13.65
Commercial	10.73	10.96	11.05
Industrial	8.64	8.85	8.79
Average large industrial customers time of use rate (cents)	8.21	8.16	8.12
Revenues – retail sales ($000's)			
Base	$ 655,327	$ 629,446	$ 620,636
Base rate adjustments	(15,731)	2,161	1,697
Sales provision adjustment	0	0	0
Total	$ 639,596	$ 631,607	$ 622,333
Revenues – retail sales per kWh (cents)			
Base	11.59	11.54	11.57
Base rate adjustments	(0.28)	0.04	0.03
Sales provision adjustment	0.00	0.00	0.00
Total	11.31	11.58	11.60
Fuel and energy cost per kWh (cents)	2.27	2.04	1.95
Fossil	3.02	2.60	2.39
Nuclear	0.58	0.58	0.61
Number of employees at year-end	1,239	1,193	1,175
Total utility employees payroll ($000's)	$ 66,155	$ 65,294	$ 68,640

(1) Includes reclassification of certain Commercial and Industrial customers.

1996	1995	1994	1993	1992	1991	1990
14,100,806	14,089,835	14,085,452	14,063,854	13,941,150	13,899,906	13,887,748
14,101,291	14,100,091	14,086,691	14,083,291	14,033,148	13,932,348	13,887,748
$ 2.88	$ 3.60	$ 3.09	$ 2.57	$ 3.76	$ 3.67	$ 3.55
$ 2.87	$ 3.59	$ 3.08	$ 2.56	$ 3.74	$ 3.66	$ 3.55
$ 31.16	$ 31.16	$ 30.39	$ 30.06	$ 30.12	$ 28.84	$ 27.35
9.20%	11.84%	10.19%	8.45%	12.67%	13.01%	13.39%
11.51%	13.04%	12.50%	10.97%	14.46%	13.39%	13.97%
$ 2.88	$ 2.82	$ 2.76	$ 2.66	$ 2.56	$ 2.44	$ 2.32
$ 39.750	$ 38.500	$ 39.500	$ 45.875	$ 42.000	$ 39.125	$ 34.125
$ 31.375	$ 29.500	$ 29.000	$ 38.500	$ 34.125	$ 30.000	$ 26.875
$ 31.375	$ 37.375	$ 29.500	$ 40.250	$ 41.500	$ 39.000	$ 31.125
$ 120,624	$ 120,033	$ 94,807	$ 104,547	$ 109,020	$ 73,865	$ 39,189
$ 47,174	$ 59,363	$ 63,044	$ 94,743	$ 66,390	$ 63,157	$ 64,018
1,895,804	1,890,575	1,892,955	1,844,041	1,799,456	1,851,447	1,826,700
2,263,056	2,273,965	2,285,942 (1)	2,359,023	2,303,216 (1)	2,347,757	2,259,340
1,143,410	1,126,458	1,135,831 (1)	1,036,547	997,168 (1)	980,071	1,060,751
48,388	48,435	48,718	50,715	52,984	55,118	58,013
5,350,658	5,339,433	5,363,446	5,290,326	5,152,824	5,234,393	5,204,804
279,024	278,326	275,441	273,752	273,936	274,064	275,637
28,666	28,550	28,394 (1)	28,968	28,848 (1)	29,768	29,808
1,652	1,599	1,538 (1)	959	1,017 (1)	268	319
1,141	1,122	1,127	1,175	1,358	1,361	1,352
310,483	309,597	306,500	304,854	305,159	305,461	307,116
14.03	13.79	13.33	12.92	12.58	12.25	11.60
11.67	11.42	10.97	10.88	11.00	10.89	10.39
9.54	9.50	9.18	9.40	9.73	9.38	8.91
8.26	8.53	8.69	8.89	8.84	8.64	8.06
$ 643,344	$ 637,219	$ 619,097	$ 605,887	$ 608,176	$ 607,997	$ 589,346
7,770	1,889	(229)	(2,328)	(41,221)	(37,497)	(45,900)
0	0	0	0	21,031	14,814	8,211
$ 651,114	$ 639,108	$ 618,868	$ 603,559	$ 587,986	$ 585,314	$ 551,657
12.02	11.93	11.54	11.45	11.80	11.62	11.32
0.15	0.04	0.00	(0.04)	(0.80)	(0.72)	(0.88)
0.00	0.00	0.00	0.00	0.41	0.28	0.16
12.17	11.97	11.54	11.41	11.41	11.18	10.60
1.69	1.71	1.76	1.75	2.43	2.67	2.63
2.41	2.22	2.14	2.08	2.98	3.11	2.89
0.46	0.85	0.94	1.23	1.42	1.62	1.55
1,287	1,358	1,377	1,490	1,554	1,571	1,587
$ 69,276	$ 72,984	$ 75,441	$ 75,305	$ 74,052	$ 71,888	$ 69,237

Executive Officers & Board of Directors

Executive Officers

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Albert N. Henricksen
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Transfer, Registrar and Dividend Disbursing Agent

American Stock Transfer & Trust Company
Telephone Inquiries:
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Email Address: info@amstock.com
Website Address: www.amstock.com

Address Shareowners inquiries to:

American Stock Transfer & Trust Company
40 Wall Street, 46th Floor
New York, NY 10005

Send Certificates for Transfer and Address Changes to:

American Stock Transfer & Trust Company
40 Wall Street, 46th Floor
New York, NY 10005

Annual Meeting Date

The Company's Annual Meeting will be held at:
Quinnipiac College
275 Mount Carmel Ave.
Hamden, CT
on Monday, June 26, 2000
beginning at 10.00 a.m.

Dividend Reinvestment Plan

Common Stock shareowners of record interested in obtaining information regarding the benefits of participating in UI's dividend reinvestment plan may write to:

American Stock Transfer & Trust Company
40 Wall Street, 46th Floor
New York, NY 10005

Investor Relations Hotline

For information on UI's earnings, news releases, media articles and dividend information, including ex-dividend dates and dividend payment dates, call:
From within the New Haven area:
(203) 499.3333 or
From outside the New Haven area:
(800) 7.CALL UI (722.5584)

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Stock Listing

New York Stock Exchange;
Common Stock (UIL)

Design: Jack Hough Associates, Inc. Norwalk CT Major Photography: David Arky and William Taufic Printing: Allied Printing Services, Inc.

Printed entirely on recycled paper

The United Illuminating Company
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P.O. Box 1564
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www.uinet.com