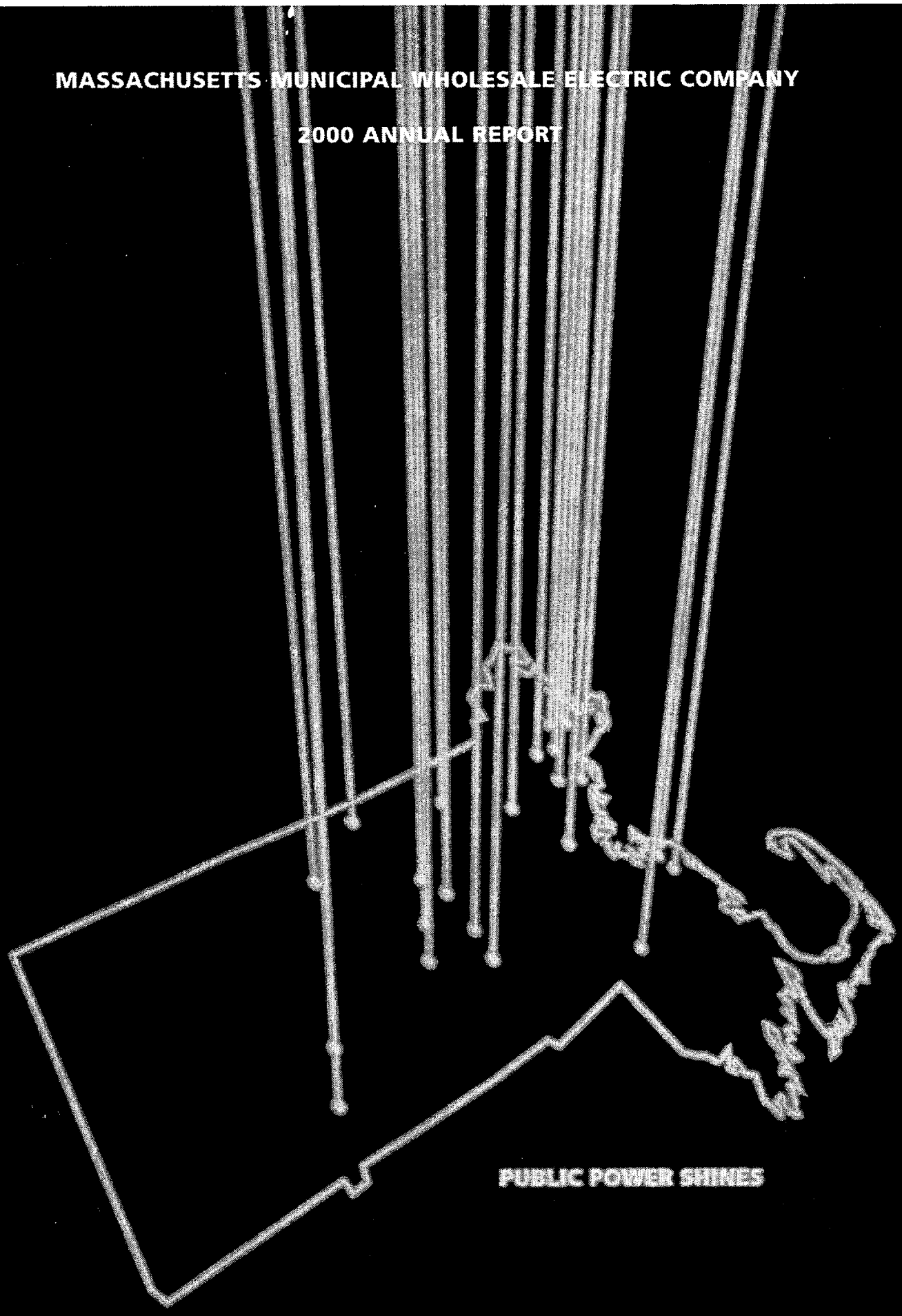
MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

2000 ANNUAL REPORT



PUBLIC POWER SHINES

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 principal 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 Electric 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 Electric 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)

"It pays to be local: Municipal electric customers dodging rate increases of big utilities"

The Boston Globe, January 26, 2001

"Small utilities offer better rates: Non-profit status helps municipal electric utilities win the rate war"

Springfield Union News, January 15, 2001

Newspaper headlines rarely tell the whole story, but these headlines from *The Boston Globe* and *Springfield Union News* reflect the strong competitive position of Massachusetts municipal utilities over the past year, a year in which consumer-owned utilities were bright spots in the midst of gloomy developments for many electricity consumers.

For MMWEC, its members and project participants, the rest of the story involves how and why most of them have overall rates that are lower than their investor-owned counterparts. A big part of the reason has to do with their cooperative participation in the expanding programs and services offered by MMWEC, the state's joint action agency for municipal utilities.

When credit rating agency Fitch, Inc. upgraded MMWEC's credit rating in November 2000 – to A-minus from BBB-plus – it cited a number of power supply, financial and strategic factors that favor MMWEC, its members and project participant utilities. A well-diversified power supply that is less sensitive to increases in natural gas and oil prices has helped municipal utilities keep their costs down. While higher fuel prices have increased the cost of electricity for all utility customers, the magnitude of the increase has been less for municipal customers due to the municipals' fuel diversity.

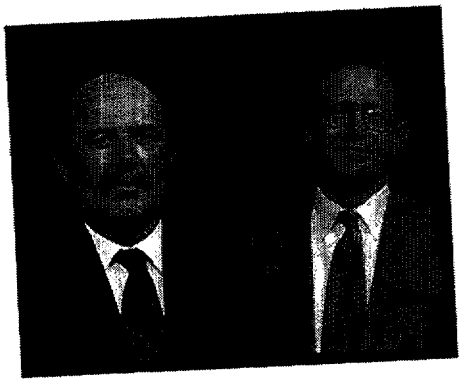
The MMWEC power supply includes ownership interests in Seabrook Station and Millstone Unit 3, New England's largest nuclear generating plants, both of which posted improved performance records over the year. Unlike most other plant owners, MMWEC did not sell its share of Millstone 3 and has no plans to sell its share of Seabrook, keeping the capacity and energy from these plants available to municipal utilities at cost, not at higher market prices. Through a contract with the New York Power Authority, MMWEC also imports nearly 82 megawatts of inexpensive hydroelectric power from New York that benefits all 40 Massachusetts municipal utilities.

Overall, a combination of diversified plant ownership, bilateral power contracts and limited purchases in the spot power markets during volatile peak periods have enabled MMWEC and its members to improve their competitive edge.

MMWEC and municipal utilities are essentially exempt from the Massachusetts electric industry restructuring law, but state and national restructuring initiatives have forever changed the environment in which MMWEC and its members operate. Acting upon the opportunities and risks that arise as restructuring continues will be extremely important, which is why MMWEC and its members are increasing their focus on strategic planning and risk management.

Individually, many MMWEC members and participants have undertaken programs to control costs and upgrade their electric distribution systems to ensure that customers continue receiving the highest quality service at the lowest possible cost. Many have established rate stabilization funds to maintain competitive rates into the future. Many also are diversifying their revenue sources by providing internet, cable TV and other telecommunications services. They are not idle spectators in these changing markets. Instead, they are hedging against adversity by adding quality, value and stability to the services they provide.

MMWEC completed a $95.8 million variable-rate bond issue in January 2001 that better positions the company to execute a much broader financial strategy. Proceeds from the variable-rate bond issue were used to purchase and retire fixed-rate MMWEC bonds, the net effect of which was to enhance the benefits of a plan to refund and



H. Bradford White, Director and Chairman of the Board (left) Roger W. Bacon, Acting General Manager

restructure all of MMWEC's $1.13 billion in outstanding debt. The full debt refunding and restructuring, planned for 2001, will give MMWEC and its participants more flexibility in managing their assets, thereby enhancing their ability to compete more effectively in the future.

MMWEC also is expanding its on-line information services so that member utilities are better able to monitor and manage their power supplies and distribution systems. Members now have instant access to a growing database of selected power supply, financial and other information about their utilities. Screening and combining information from a variety of sources to produce timely and strategic on-line reports for members is an increasingly important role for MMWEC.

In addition, MMWEC is putting the finishing touches on an effort to establish new service relationships with its member utilities. Once in place, this initiative will enable members to choose a service agreement with MMWEC that best meets their individual system needs. The current single service agreement that all members must sign will be replaced with two agreements that give current and prospective members more choices and more flexible service options.

The continuing energy crisis in California and the West is providing many lessons for those involved in electric industry restructuring. One of the most enlightening lessons is about the value of public power as a yardstick to measure the effectiveness of restructuring. With consumer-owned utilities faring better than most, the California situation has produced calls for public control of electric facilities and an unwieldy backlash by consumers demanding more input on decisions affecting the cost and reliability of electric service.

As New England and the Northeast continue to restructure their wholesale power markets, MMWEC is working to ensure that consumers retain a decisional role in developing power market rules, building new facilities and establishing the terms, conditions and rates for transmission service. Not surprisingly, the call for establishment of Regional Transmission Organizations has yielded self-interested proposals from transmission owners and generators, both of which seek to eliminate consumer input.

MMWEC is pursuing many other important activities. After years of work, a decision is pending from the Massachusetts Energy Facilities Siting Board on MMWEC's proposal to build a natural gas pipeline to better service its Stony Brook power plant. We also are pursuing a new business initiative that could expand MMWEC's customer base to include aggregated municipal loads. More detail on these and other activities are contained in the body of this report.

In order to achieve its many objectives, MMWEC maintains a highly skilled professional staff, dedicated to the mission and values of public power. The staff works closely with the Board of Directors and member utilities, whose managers and facilities are pictured on the following pages. Holding everyone together and driving us forward is a deep-seated belief in the power and force of joint action. Cooperation is the foundation of many great achievements, and working together we will keep the time-tested tradition of public power alive and thriving in Massachusetts.

H. Bradford White
Director and Chairman of the Board

Roger W. Bacon
Acting General Manager

MMWEC provides its members and participants with a wide range of financial expertise and services, from financial analysis, project financing and accounting services, to investment management, budgeting and financial reporting services. These services are employed in managing the $1.13 billion in outstanding MMWEC bonds, as well as the approximate $28 million in outstanding commercial paper.

MMWEC has issued its bonds to finance and refinance its ownership interests in several power plants, including Seabrook Station, Millstone Unit 3, Stony Brook and Wyman Unit 4. The commercial paper financing program was established in 1998 to finance the buyout of high-priced power contracts, an activity that ultimately will save an estimated $34 million for municipal utilities. Management of these funds involves the investment and management of bond proceeds and debt service payments; the preparation of data and reports to meet regulatory, financial and other reporting requirements; and the preparation and management of company and project budgets.

Early in 2001, MMWEC began implementing a major financial restructuring program that will give MMWEC and its

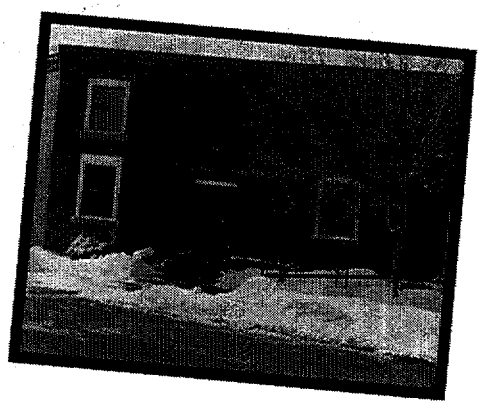
Danvers
Electric Division

Electric Utility Director:
Coleen M. O'Brien-Pitts
Danvers Customers: 11,735
Peak Load: 66.01 MW

MMWEC Power Supply Projects

Project Name	Generating Unit	Ownership Share (MW)	Amount of Bonds Outstanding
Peaking Project	Stony Brook	170.0	$ 23,020,000
Intermediate Project	Stony Brook	319.5	$ 81,375,000
Wyman Project	W.F. Wyman No. 4	22.7	$ 3,830,000
Nuclear Project No. 3	Millstone Unit 3	36.8	$ 184,670,000
Nuclear Mix No. 1*	Millstone Unit 3 Seabrook Station	18.4 1.9	$ 110,465,000
Nuclear Project No. 4	Seabrook Station	49.8	$ 212,115,000
Nuclear Project No. 5	Seabrook Station	12.6	$ 64,635,000
Project No. 6	Seabrook Station	69.0	$ 449,560,000
Totals:		700.7	$1,129,670,000

** Nuclear Mix No. 1 includes ownership shares in both Seabrook Station and Millstone Unit 3.*



Finance

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Peaking Project	**Stony Brook**	**170.0**	**$ 23,020,000**
Intermediate Project	**Stony Brook**	**[illegible]**	**$ [illegible]**
Wyman Project	**W.F. Wyman No. 4**	**22.7**	**$ 3,830,000**
Nuclear Project No. 3	**Millstone Unit 3**	**[illegible]**	**$ [illegible]**
Nuclear Mix No. 1*	**Millstone Unit 3** **Seabrook Station**	**18.4** **1.9**	**$ 110,465,000**
Nuclear Project No. 4	**Seabrook Station**	**[illegible]**	**$ [illegible]**
Nuclear Project No. 5	**Seabrook Station**	**12.6**	**$ 64,635,000**
Project No. 6	**Seabrook Station**	**[illegible]**	**$ [illegible]**
Totals:		**700.7**	**$1,129,670,000**

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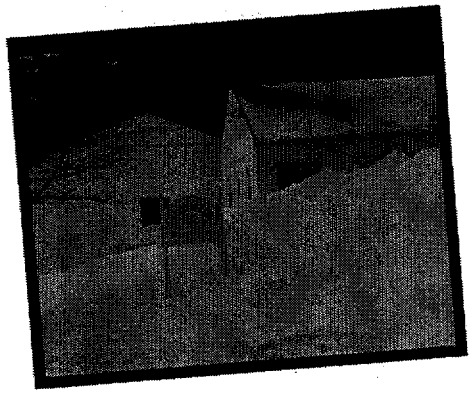


Ashburnham Municipal Light Plant

Manager: Stanley Herriott, Ashburnham Customers: 2,655 Peak Load: 5.84 MW

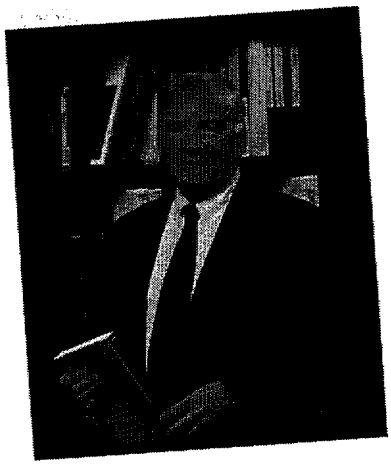
municipal utilities the financial flexibility they need to compete more effectively in a restructured electric industry. The program involves restructuring of the MMWEC General Bond Resolution and a new bond issue to refund the $1.13 billion in outstanding MMWEC bonds. Activities in March and April of 2001 have included visits to bond insurance companies and credit rating agencies to explain the restructuring program, which is planned for implementation around mid-2001, depending on bond market conditions and a number of other factors.

In April 2000, MMWEC obtained approval from the Massachusetts Department of Telecommunications and Energy (DTE) to refund all of its outstanding bonds. The DTE decision authorizes MMWEC to issue approximately $1.6 billion in bonds or other forms of indebtedness to accomplish the refunding. The authorized amount includes a 10 percent contingency and significant amounts necessary to cover financing options available to MMWEC. The exact amount of a refunding bond issue will depend on the ultimate structure of the financing and interest rates at the time of issue.

Refunding all of its bonds will enable MMWEC to restate and amend its existing General Bond Resolution, the document that governs MMWEC bond issues, including the investment of bond proceeds. In its findings, the DTE stated that amending the bond resolution will improve MMWEC's "operating and financial flexibility, resulting in subsequent savings to the MMWEC participants and ultimately the ratepayers."

Among other things, an amended and restated General Bond Resolution will include less restrictive debt covenants that will increase the asset-management options available to MMWEC. It also will ease restrictions on the sale of project assets and eliminate a joint pledge of all project revenues that links MMWEC's eight power supply projects financially. Currently, all revenues MMWEC derives from all of its projects are dedicated to satisfying the obligations of all bonds. Eliminating this joint pledge of revenues will require the establishment of independent and separately-rated financings for each power supply project, yielding greater flexibility in managing individual projects.

Preparation for the refunding and restructuring of MMWEC's debt also involved the issuance of $95.8 million in variable-rate bonds in January 2001. Proceeds of this bond issue were used to purchase and



retire a similar amount of fixed-rate MMWEC bonds. Among the now-retired bonds are ones that were previously refunded and could not be refunded again on a tax-exempt basis. Retiring these bonds has enabled MMWEC to limit or eliminate the need to issue more expensive taxable bonds as part of the full debt refunding plan.

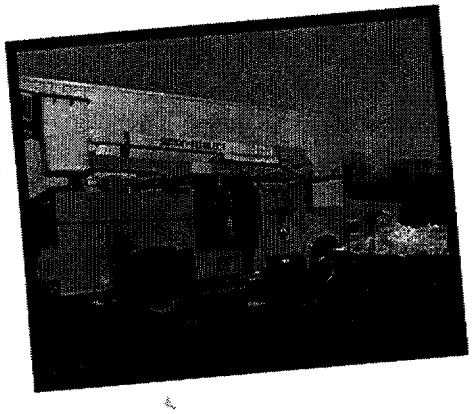
The DTE issued another important decision on Jan. 30, 2001 involving the ability of municipal utilities to recover stranded costs associated with their MMWEC power contracts. In its decision, the DTE states that "the public interest in preserving MMWEC's essential public function and protecting public financing" are served by requiring a "customer" of an MMWEC project participant to pay a portion of the costs associated with MMWEC's contracts if they obtain service from another supplier.

The DTE decision came in a case remanded by the Massachusetts Supreme Judicial Court (SJC), which ruled in 1998 that the Hudson Light & Power Department, an MMWEC project participant, was entitled to recover a share of its contract costs from the Town of Stow. Served by the Hudson utility for nearly a century, Stow was seeking to sever its ties with Hudson and argued that it was not obligated to pay any of Hudson's power contract costs if it obtained alternate service.

The DTE decision solidifies the legal principles established by the SJC regarding recovery of stranded costs associated with MMWEC's contracts. If municipal utilities open their service territories to competition, these principles would be applied in support of efforts to recover MMWEC contract costs from departing municipal utility customers.

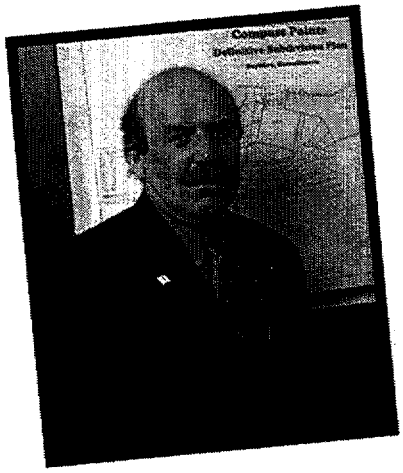
Belmont
Municipal Light Department

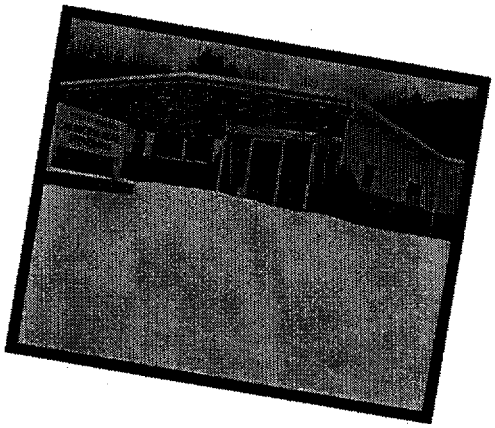
Manager: Timothy L. McCarthy
Belmont Customers: 10,723
Peak Load: 27.84 MW



Concord
Municipal Light Plant

Superintendent: Daniel J. Sack
Concord Customers: 7,324
Peak Load: 37.64 MW



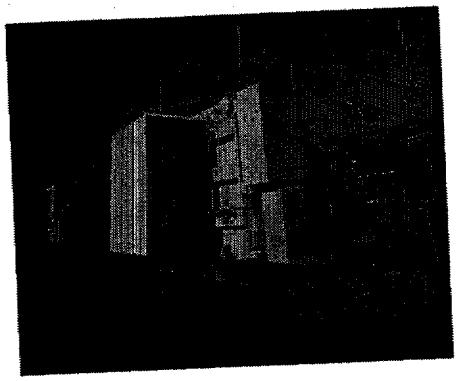


Boylston
Municipal Light Department

Manager: H. Bradford White Jr.
Boylston Customers: 2,317
Peak Load: 5.20 MW

Hingham
Municipal Lighting Plant

General Manager:
Christopher A. Cox
Hingham Customers: 9,904
Peak Load: 33.88 MW



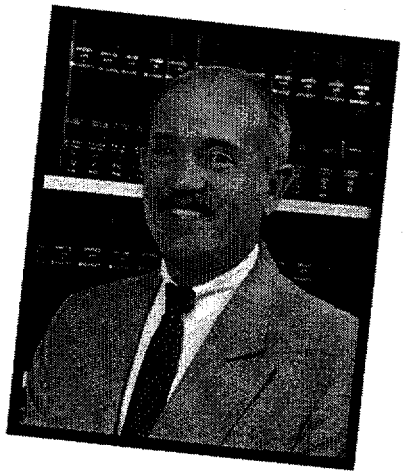
Another way MMWEC and its participants are strengthening their competitive position is through the establishment of reserve funds to offset future above-market power supply costs. MMWEC has established a reserve trust for participants to set aside funds to mitigate above-market cost exposures, and many participants have established rate stabilization funds for the same purpose. Some members and participants also are maintaining higher balances in their depreciation funds, which can be used for system improvements and to meet other system needs. These efforts will help participants maintain competitive rates and quality service following the transition to a fully competitive market for electric generation.

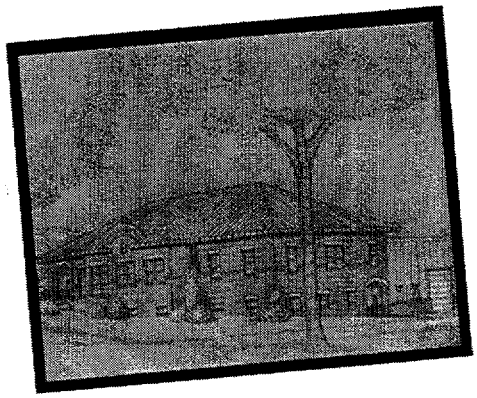
In the meantime, the combination of MMWEC financial initiatives and individual participant actions is keeping MMWEC, its members and project participants on solid financial ground. The fact that the rates charged by Massachusetts investor-owned utilities have increased significantly over the past year – some in excess of 40 percent – gives the municipals an added measure of flexibility in meeting their current and long-term financial needs.

Power

One of MMWEC's most important functions is to help its member utilities meet their power supply requirements through the bulk purchase of electric generating resources. Electric industry restructuring has complicated this function with the establishment of competitive bulk power markets, an avalanche of new market participants and the sale of power plants to unregulated generating companies. However, MMWEC is using its unique market position to the best advantage of its members and project participants.

In 1975, when it became a political subdivision and public corporation, MMWEC gained the authority to issue tax-exempt revenue bonds to finance a municipal power supply program, including joint ownership interests in power projects.





Today, MMWEC owns approximately 700 megawatts of generating capacity in four plants: the Seabrook Station and Millstone Unit 3 nuclear plants, the natural gas- and oil-fired Stony Brook plants, and the oil-fired Wyman Unit 4. MMWEC sells the output from its ownership shares in these plants to its power project participants at cost, which translates into a significant advantage for participants in today's marketplace. Several MMWEC participants also own a combined total of approximately 220 megawatts in local generating capacity independent of MMWEC, with the output of these local plants also available to these participants at cost.

The situation of MMWEC and its participants with respect to plant ownership stands in stark contrast to that of New England's investor-owned utilities, which have sold most of their ownership interests in power plants to independent generating companies. These generating companies now sell energy for profit into New England's wholesale power markets at prices as high as the markets will bear. At times when market prices exceed the cost of production, as they often do, sometimes significantly, MMWEC's participants receive energy at cost from the MMWEC- and participant-owned plants, resulting in lower costs for the participant municipal utilities.

Investor-owned utilities are divesting their generating resources as a result of electric industry restructuring laws that either require or strongly encourage divestiture. MMWEC and municipal utilities are exempt from most provisions of the Massachusetts restructuring law, including provisions encouraging the sale of generation.

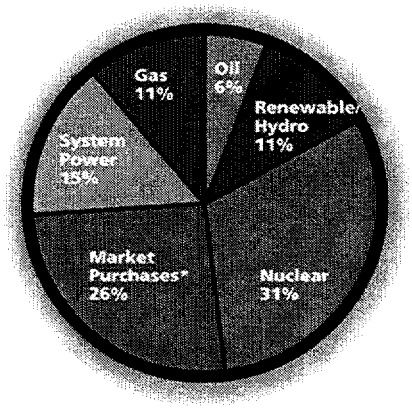
MMWEC decided to retain its 55.2-megawatt ownership in Millstone Unit 3 when other plant owners sold their shares of the 1,150-megawatt plant to a subsidiary of Dominion Resources, a Virginia-based generating company. Although responsibility for operation of the plant transferred in April 2001 from Northeast Utilities to Dominion, MMWEC asserted its rights under the Millstone 3 ownership agreement during the sale process and remains actively involved in plant oversight.

MMWEC also has no plans to sell its 133-megawatt ownership in Seabrook Station. Utilities owning more than 85 percent of Seabrook, including lead owner and operator Northeast Utilities, will put their Seabrook shares on the market and hope to close on a sale by the end of 2001. Exercising its rights under the Seabrook joint ownership agreement, MMWEC has been and will continue to be involved in discussions and

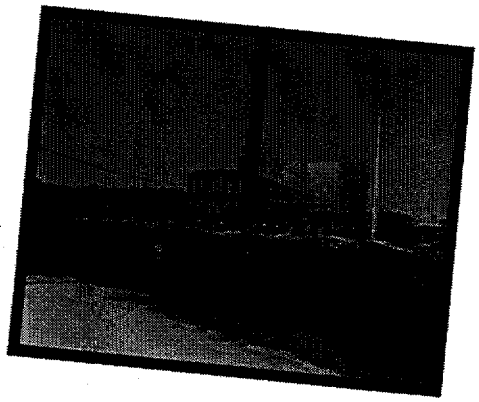
Holden
Municipal Light Department

Manager Municipal Lighting:
Brian J. Bullock
Holden Customers: 6,652
Peak Load: 29.23 MW

MMWEC Fuel Mix



* System Power consists primarily of contract purchases from various units at fixed terms and prices. System Power fuel type varies, as does the fuel type of market purchases.



Holyoke
Gas & Electric Department

General Manager: James M. Lavelle
Holyoke Customers: 15,660
Peak Load: 64.20 MW

negotiations involving the sale to ensure that its rights are protected.

MMWEC's ownership of electric generating capacity, and the sale of that capacity at cost to its participants, will continue to be a competitive advantage for municipal utilities. With municipal utility power requirements growing, MMWEC is exploring additional purchase options to meet its members' needs. These options include the construction or lease of new capacity, including distributed generation, as well as the purchase of ownership shares in new or existing generating facilities.

While MMWEC is a minority owner of the Seabrook, Millstone and Wyman plants, it is the lead owner and operator of Stony Brook, a combined-cycle intermediate and peaking plant with a total capacity of approximately 520 megawatts. This brings with it added responsibilities for Stony Brook operations, but it also brings a deeper understanding of generators and power market procedures, which enhances MMWEC's market insight.

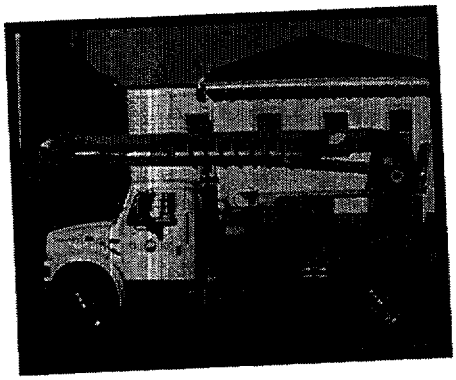
MMWEC completed a variety of projects in the past year to make Stony Brook more reliable and efficient.

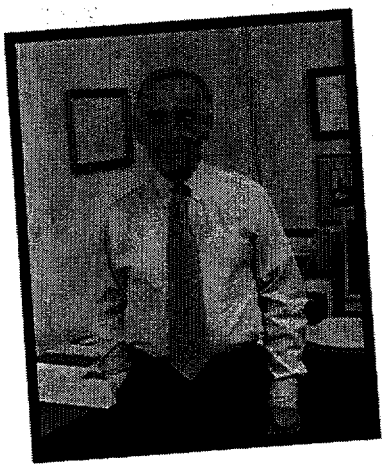
The installation of inlet fogging systems on Stony Brook's three Intermediate Unit combustion turbines significantly increased the unit's summer output capability. Gas turbine generators suffer thermodynamic changes in the summer months that reduce their generating capability. The inlet fogging systems inject a fine mist or "fog" into a turbine's inlet air stream, which cools the air used in the combustion process and partially offsets the adverse effects of hotter summer air on turbine operation and output.

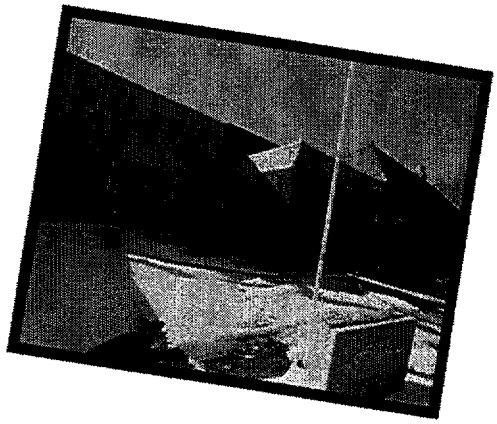
Depending on temperatures and other conditions, the inlet fogging systems can increase the Intermediate Unit's output by more than 10 megawatts. Identical fogging systems being installed on the Stony

Hull
Municipal Lighting Plant

Manager: John A. MacLeod
Hull Customers: 5,672
Peak Load: 10.49 MW







Brook Peaking Unit's two combustion turbines will boost the output capability of the Peaking Unit, providing participants with additional capacity during summer peak periods. MMWEC also completed major overhauls of the Peaking Unit turbines, replacing and upgrading major components to ensure the continued reliability and efficiency of the unit.

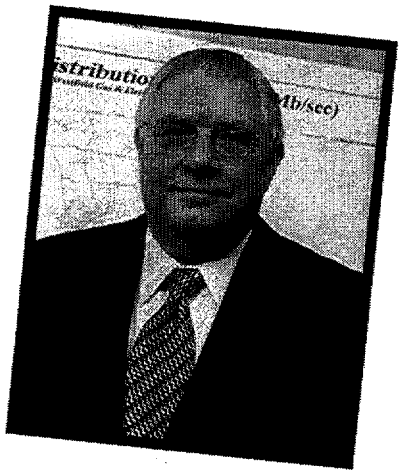
Efforts to increase the supply of natural gas to Stony Brook have moved forward, with a decision on MMWEC's petition for authority to build a natural gas pipeline expected from the state Energy Facilities Siting Board before mid-2001. Hearings before the siting board, which closed late in 2000, required MMWEC responses to more than a thousand information requests and the preparation of more than 100 economic analyses. The pipeline will increase Stony Brook's natural gas generating capability, reduce the plant's emissions rates and is projected to reduce participants' power costs by approximately $18.4 million over 20 years.

Early in October 2000, a transformer fault and fire in Stony Brook's switchyard tested MMWEC's preparedness for emergencies. The injury-free incident resulted in an unplanned outage for the plant, but MMWEC was able to bring Stony Brook back on line in just over three days. After gaining control of the fire and its aftermath, the spare high-voltage transformer was connected and the plant was returned to service. A replacement transformer is on order, with delivery expected late in 2001.

In addition to upgrading and maintaining plant equipment, MMWEC is responsible for purchasing oil and natural gas for Stony Brook, as well

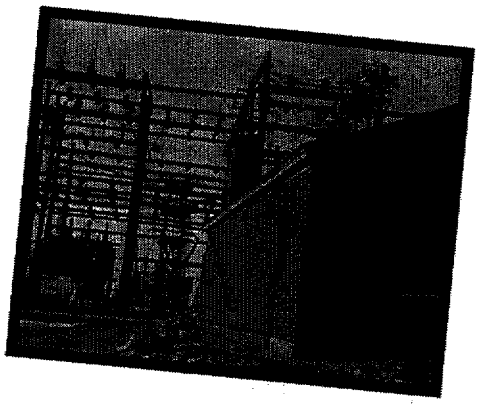
Ipswich
Municipal Light Department

Manager: Raymond R. Shockey
Ipswich Customers: 6,444
Peak Load: 18.53 MW



Westfield
Gas & Electric Light Department

General Manager: Daniel Golubek
Westfield Customers: 16,706
Peak Load: 69.72 MW

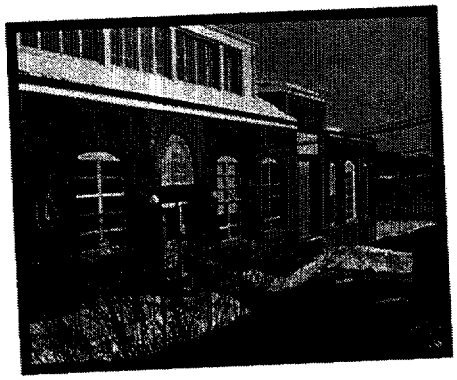


Mansfield
Municipal Electric Department

Manager: Jack Beliveau
Mansfield Customers: 8,722
Peak Load: 38.20 MW

Marblehead
Municipal Light Department

Manager: Robert V. Jolly Jr.
Marblehead Customers: 10,404
Peak Load: 24.92 MW



as developing and submitting bids used by ISO-New England to determine which plants are dispatched to meet New England's hourly power needs. In performing these duties, MMWEC has gained an in-depth understanding of the highly competitive and interrelated markets for fuel and electric energy.

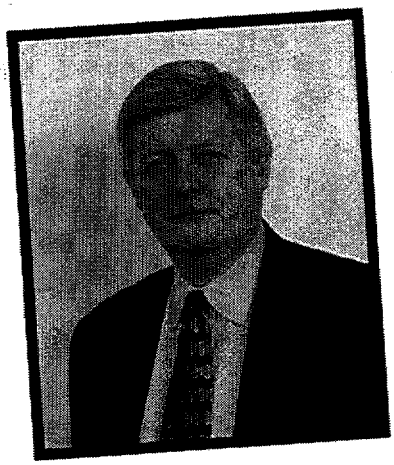
Since the launch of New England's bid-based wholesale power markets in mid-1999, MMWEC has been acquiring the knowledge and technical resources required to ensure that its members are active and effective participants in these markets. It also has increased its focus on tactical planning and risk management so that it can identify and gauge the risks of emerging opportunities.

Managing power supplies in today's marketplace requires the input and analysis of information from a variety of sources. Knowledge of fuel prices, load projections, available capacity, power market bidding procedures and power contracting opportunities are among the many factors to be considered in making power supply decisions. In its various roles as a power generator, broker, supplier and distributor, MMWEC is uniquely positioned to gather and integrate these diverse inputs to arrive at comprehensive solutions to its members' power needs.

Standing

MMWEC and Massachusetts municipal utilities have won countless legal and regulatory battles over the past 30 years to improve their standing within New England's electric utility industry.

In the late '60s and early '70s, a series of favorable decisions from federal regulators and courts enabled municipal utilities to participate as equals in the establishment of the New England Power Pool (NEPOOL). Subsequently, the municipals and MMWEC gained the right to purchase and finance ownership shares in the region's major power plants, which led to creation of an independent public power supply program for municipal utilities.



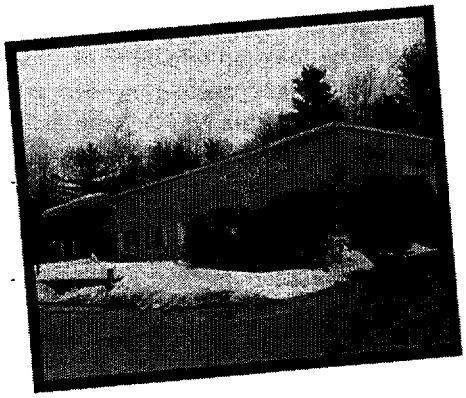
In 1985, after 10 years of litigation spearheaded by MMWEC, Massachusetts municipal utilities won the right to receive a share of inexpensive preference power from federal hydroelectric projects in New York. The municipals now receive about 82 megawatts of this hydropower at a delivered cost of about 1.5 cents/kilowatt hour, yielding annual savings of about $13 million for municipal utility consumers.

During the past year, MMWEC's role as an advocate for its members' rights gained importance as the number and significance of proposals affecting municipal utility interests increased. Restructuring of New England's electric industry is continuing on a daily basis, with everything from proposals to change the design and rules of wholesale power markets, to the radical industry restructuring contemplated in a Regional Transmission Organization (RTO) proposal. In order to protect its members' economic and legal rights, MMWEC has been an aggressive participant in the various forums where these issues are being discussed and litigated.

Debates over the design and rules of New England's wholesale power markets are taking place within NEPOOL and before the Federal Energy Regulatory Commission (FERC). The FERC has conditionally approved the framework for establishment of congestion management and multi-settlement systems within these markets, and MMWEC is working to ensure that municipal utility concerns are fairly considered in implementing these new systems.

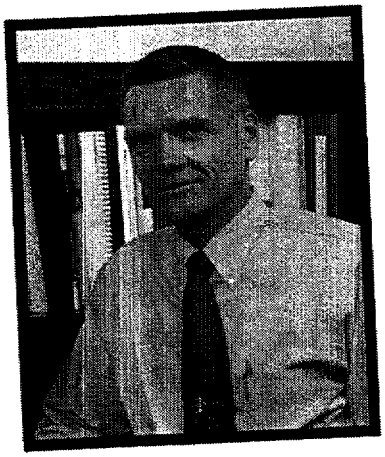
Middleton
Municipal Electric Department

Manager: Mark T. Kelly
Middleton Customers: 2,871
Peak Load: 20.68 MW



Paxton
Municipal Light Department

Manager: Diane Dillman
Paxton Customers: 1,737
Peak Load: 4.38 MW

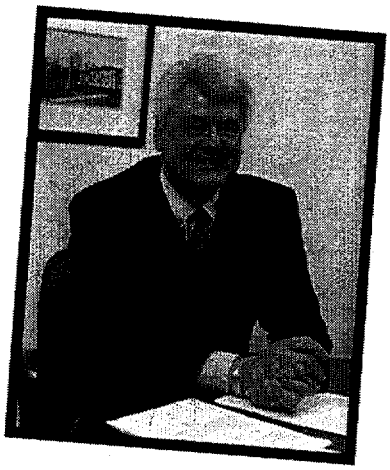


Rowley
Municipal Lighting Plant

Manager: *Carl Benson*
Rowley Customers: *2,439*
Peak Load: *6.75 MW*

Shrewsbury's
Electric Light Plant

General Manager: *Thomas R. Josie*
Shrewsbury Customers: *13,619*
Peak Load: *55.70 MW*



Late in 2000, MMWEC asked the FERC to reject a proposal by ISO-New England, the region's independent system operator, to revise its tariff in ways that would significantly increase costs for the MMWEC members and other municipal utilities. The ISO tariff is the vehicle for allocating the ISO's expenses, which have increased dramatically in the past five years, from approximately $15 million to almost $75 million. In its filing to the FERC, MMWEC states that the tariff proposal unjustifiably burdens municipal utilities by seeking to implement a new billing scheme that shifts more of the ISO's costs to smaller participants. MMWEC is working to achieve a settlement of the ISO tariff issues.

In another filing to the FERC, MMWEC and other public power utilities are seeking more timely release of wholesale market data needed to facilitate the type of market monitoring that discourages anti-competitive behavior by market participants. Keeping information about bidding activity and bidders secret can provide a cover for possible collusion among market participants and thwarts the development of open, workably competitive power markets. MMWEC states in its filing.

In a FERC case with huge significance, MMWEC was joined by a coalition of New England's consumer-owned utilities in protesting the January 2001 RTO filing of six New England transmission owners and ISO-New England. This filing proposes to give control over the region's transmission system to a new "independent transmission company" while stripping NEPOOL participants of their hard-won rights to vote on the terms, conditions and pricing of transmission service. Doing so would eliminate any effective role for consumers in key decisions affecting the cost and reliability of electric service, as consumer interests are represented within NEPOOL by the public power and end user governance sectors of the pool.

Groton
Electric Light Department

Manager: Roger H. Beeltje
Groton Customers: 4,712
Peak Load: 11.35 MW

There are many other onerous components of this RTO proposal, which MMWEC and the public power coalition expose in several hundred pages of pleadings to the FERC. Debates over the formation of a New England RTO will no doubt continue for many months to come, and MMWEC will continue its effort to protect the rights and interests of its members as the process moves forward.

Also in the past year, MMWEC has been working to protect and enhance the Massachusetts allocation of hydroelectric preference power from New York. A one-year extension of the hydropower contract with the New York Power Authority was executed in March 2001, extending the contract until mid-2002. An agreement between MMWEC and the Massachusetts Department of Telecommunications and Energy under which MMWEC manages the allocation also has been extended for a year. MMWEC will remain vigilant on this front as contract extension and hydroelectric project relicensing activities intensify.

These are only a few of the cases and issues that occupy MMWEC in its role as an advocate for the interests of its member utilities. Much of this activity takes place within NEPOOL and at the FERC, but MMWEC also pursues its public power agenda in meetings with state and federal legislators and in other forums where a public power perspective is needed.

Sterling
Municipal Light Department

Manager: John Kilgo Jr.
Sterling Customers: 3,423
Peak Load: 9.01 MW

Templeton Municipal Lighting Plant

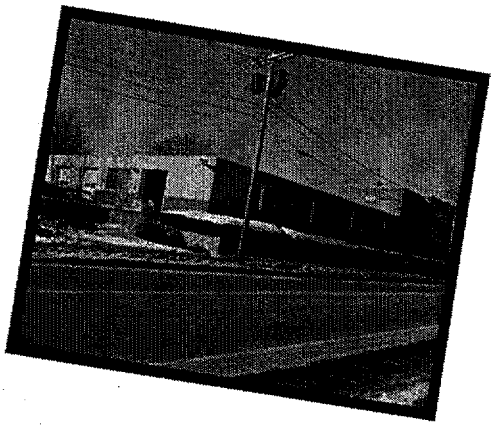
Manager: Gerald P. Skelton
Templeton Customers: 3,044
Peak Load: 10.45 MW

Service

With few exceptions, change may be the only constant in today's electric utility industry. Among the exceptions are the enduring values of public power and MMWEC's commitment to meeting the needs of its member utilities. But as the electric industry changes, so do the needs of MMWEC's members, which is why MMWEC is working constantly to update and improve its programs and services.

One of these improvements is aimed at giving MMWEC's current and prospective members more choice and flexibility in the services they receive. Since 1976, signature of a standard Service Agreement has been mandatory for all MMWEC members. This agreement provides members with the full array of MMWEC services. Recognizing that in today's world all members may not need the full contingent of services, MMWEC is working to establish new service agreements that provide members with different service options. Under this revised service plan, which could be available by mid-2001, members would choose one of two service agreements with MMWEC to best meet their individual system needs.

To keep its members better informed of activity in wholesale power markets, MMWEC now offers a variety of on-line information that helps members monitor and manage their power supplies. By combining information from its own database with information from ISO-New England, MMWEC can produce electronic near-real-time reports on each member's market position. These reports, mostly in the form of tables and graphs, are available on MMWEC's Internet website for member utilities. Among many other things, the on-line reports provide information on bulk power costs, metered loads, loads and capacity, the market value of members' resources and stranded costs.



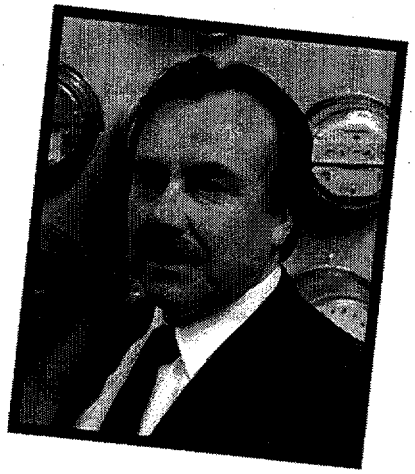
In an effort to expand its customer base that holds significant potential for public benefit, MMWEC also is pursuing a new business initiative that involves the provision of power supply services to aggregated municipal loads. While this effort is still in its formative stages, MMWEC is excited about the prospect of working with municipalities to contain power costs while at the same time spreading its service costs over a broader customer base.

Another new service provides members with daily e-mail updates on news and events in the electric industry. From news about local events and issues to updates on the California energy crisis, this service gives members a quick and easy way to keep abreast of issues that could affect their utilities.

By adapting to change, managing risks and taking advantage of new opportunities, MMWEC is working to secure a positive future for public power in Massachusetts. Joint action by MMWEC and its members has been the key to many successful initiatives, and it will provide the strength needed to conquer the challenges that lie ahead.

Wakefield
Municipal Gas & Light Department

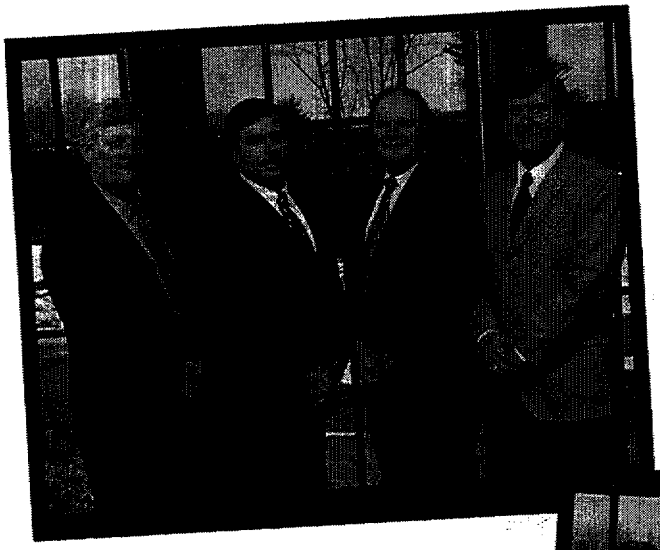
Manager: William J. Wallace
Wakefield Customers: 11,295
Peak Load: 38.29 MW



West Boylston
Municipal Lighting Plant

Manager: John Scirpoli
West Boylston Customers: 3,275
Peak Load: 11.00 MW

DIRECTORS AND OFFICERS



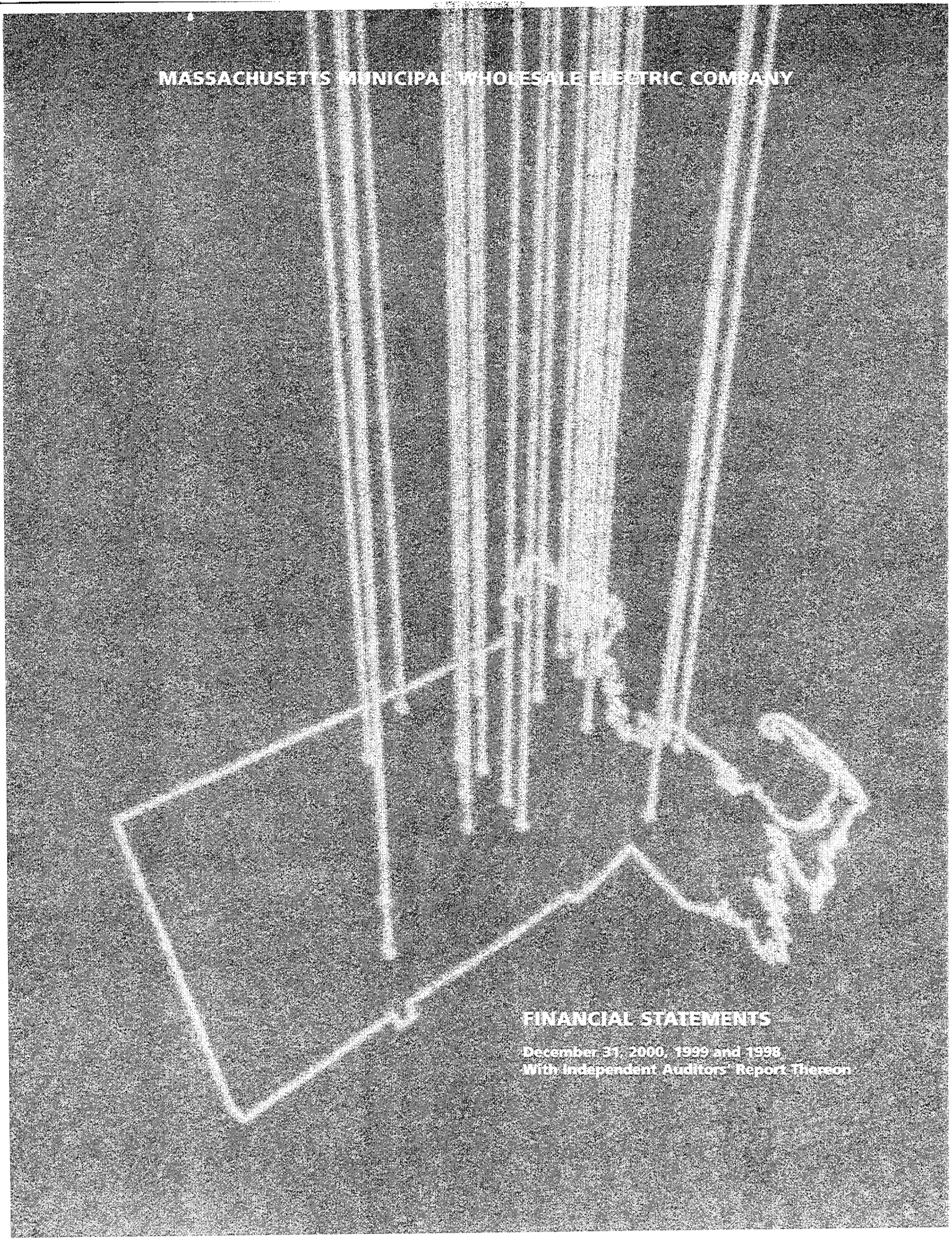
◀
(Left to right)
Mark T. Kelly, Director
Michael J. Flynn, Director
William J. Wallace, Director
Robert V. Jolly, Jr., Director

▶
Gerald P. Skelton, Director and Treasurer
Daniel Golubek, Director
Luis Vitorino, Director
John M. Flynn, Director

◀
Nicholas J. Scobbo, Jr.,
General Counsel
Ronald C. DeCurzio, Assistant Treasurer
Joseph O. Roy, Assistant Secretary

Not Pictured:
Timothy L. McCarthy, Director
Maria F. Gomes,
Director/Gubernatorial Appointee
Raymond R. Shockey, MMWEC President

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY



FINANCIAL STATEMENTS

December 31, 2000, 1999 and 1998
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, 2000, 1999 and 1998 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 auditing standards generally accepted in the United States of America. 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, 2000, 1999 and 1998, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

March 2, 2001

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

STATEMENTS OF FINANCIAL POSITION

December 31, 2000, 1999 and 1998

(In Thousands)	2000	1999	1998
ASSETS			
Electric Plant			
In Service (Note 5)	$1,242,148	$1,240,200	$1,238,454
Accumulated Depreciation	(544,741)	(500,389)	(456,650)
	697,407	739,811	781,804
Nuclear Fuel - Net of Amortization	12,108	9,736	12,164
Total Electric Plant	709,515	749,547	793,968
Special Funds (Notes 2, 4 and 6)	250,628	241,042	239,547
Current Assets			
Cash and Temporary Investments (Note 6)	915	1,081	1,718
Accounts Receivable	9,805	6,580	6,678
Unbilled Revenues (Note 2)	12,204	3,300	3,776
Inventories (Note 2)	13,679	18,505	13,747
Prepaid Expenses	6,434	6,470	8,488
Total Current Assets	43,037	35,936	34,407
Total Special Funds and Current Assets	293,665	276,978	273,954
Deferred Charges			
Amounts Recoverable Under Terms of the Power Sales Agreements (Note 2)	219,395	238,565	223,670
Unamortized Debt Discount and Expenses	20,089	22,448	24,815
Nuclear Decommissioning Trusts	21,882	18,142	14,713
Other	8,072	6,308	6,024
	269,438	285,463	269,222
	$1,272,618	$1,311,988	$1,337,144
LIABILITIES			
Long-Term Debt			
Bonds Payable (Note 4)	$1,079,090	$1,130,215	$1,178,085
Current Liabilities			
Current Maturities of Long-Term Debt (Note 4)	50,580	47,870	44,650
Commercial Paper (Note 4)	28,025	36,765	21,205
Notes Payable (Note 4)	50	82	—
Accounts Payable	9,285	9,860	7,514
Accrued Expenses	35,851	21,501	17,696
Member and Participant Advances and Reserves	47,331	46,915	52,538
	171,122	162,993	143,603
Deferred Credits	22,406	18,780	15,456
Commitments and Contingencies (Note 10)			
	$1,272,618	$1,311,988	$1,337,144

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

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

STATEMENTS OF OPERATIONS

Years Ended December 31, 2000, 1999 and 1998

(In Thousands)	2000	1999	1998
Revenues (Note 3)	$276,340	$232,094	$227,949
Interest Income	17,327	15,409	15,286
Total Revenues and Interest Income	$293,667	$247,503	$243,235
Operating and Service Expenses:			
Fuel Used in Electric Generation	$ 31,841	$ 28,290	$ 27,530
Purchased Power	69,241	37,420	41,754
Other Operating	40,841	39,367	35,028
Maintenance	16,862	15,207	12,108
Depreciation	45,205	45,032	44,837
Taxes Other Than Income	5,180	5,645	5,652
	209,170	170,961	166,909
Interest Expense:			
Interest Charges	67,881	68,796	70,711
Interest Charged to Projects During Construction (Note 2)	(122)	(19)	(95)
	67,759	68,777	70,616
Total Operating Costs and Interest Expense	276,929	239,738	237,525
Other (Note 8)	(43)	18,874	22,000
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements (Note 2)	16,781	(11,109)	(16,290)
	$293,667	$247,503	$243,235

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

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

STATEMENTS OF CASH FLOWS

Years Ended December 31, 2000, 1999 and 1998

(In Thousands)	2000	1999	1998
Cash flows from operating activities:			
Total Revenues and Interest Income	$ 293,667	$ 247,503	$ 243,235
Total Costs and Expenses, net	(276,886)	(258,612)	(259,525)
Adjustments to arrive at net cash provided by operating activities:			
Depreciation and Decommissioning	47,713	47,502	46,609
Amortization	7,354	7,829	6,635
Change in current assets and liabilities:			
Accounts Receivable	(3,225)	98	2,556
Unbilled Revenues	(8,904)	476	1,817
Inventories	4,826	(4,758)	716
Prepaid Expenses	36	2,018	(1,465)
Accounts Payable	(575)	2,346	(4,727)
Accrued Expenses and Other	12,501	3,413	2,027
Member and Participant Advances and Reserves	416	(5,623)	5,236
Net cash provided by operating activities	76,923	42,192	43,114
Cash flows from investing activities:			
Construction Expenditures and Purchases of Nuclear Fuel	(10,168)	(6,037)	(8,171)
Interest Charged to Projects During Construction	(122)	(19)	(95)
Net Increase in Special Funds	(9,586)	(1,495)	(13,406)
Change in net Unrealized Gain (Loss) on Special Funds	2,389	(3,785)	934
Decommissioning Trust Payments, net	(3,740)	(3,429)	(2,641)
Other	1,397	1,087	1,062
Net cash used for investing activities	(19,830)	(13,678)	(22,317)
Cash flows from financing activities:			
Payments for Principal of Long-Term Debt and Commercial Paper	(57,155)	(48,230)	(42,610)
Proceeds from Commercial Paper	—	19,140	22,500
Payments for Commercial Paper Issue Costs	(72)	(143)	(276)
Change in Notes Payable	(32)	82	—
Net cash used for financing activities	(57,259)	(29,151)	(20,386)
Net increase (decrease) in cash and temporary investments	(166)	(637)	411
Cash and Temporary Investments at Beginning of Year	1,081	1,718	1,307
Cash and Temporary Investments at End of Year	$ 915	$ 1,081	$ 1,718
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 65,004	$ 65,885	$ 67,714

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

NOTES TO FINANCIAL STATEMENTS

(1) Nature of Operations

The Massachusetts Municipal Wholesale Electric Company (MMWEC) is a public corporation and a political subdivision of the Commonwealth of Massachusetts (Commonwealth) 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, in part derived from Power Sales Agreements (PSAs) with its members and other utilities. The power supply program consists of power purchase arrangements, power brokering services, planning and financial services, and the Projects relating to generating facilities either built and operated by MMWEC or other regional 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, 2000, 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 (GAAP) 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 seven years. At December 31, 2000, MMWEC's share of Millstone Unit 3 and Seabrook Station unbilled assessments were $285,000 and $435,000, 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)	2000	1999	1998
Fund			
Bond Fund Interest, Principal and Retirement Account to pay principal and interest on bonds	$ 46,896	$ 45,427	$ 43,742
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	79,396	77,904	80,216
Reserve and Contingency Fund to make up deficiencies in the Bond Fund and pay for renewals and extraordinary costs	26,899	24,113	22,840
Revenue Fund to receive revenues and disburse them to other funds	79,084	73,625	66,842
Working Capital Funds to maintain funds to cover operating expenses	18,353	19,973	25,907
Total Special Funds	$250,628	$241,042	$239,547

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.

Inventories

Fuel oil and spare parts inventory are recorded and accounted for by the average cost method. At December 31, 2000, 1999 and 1998, fuel oil inventory was valued at $4.8, $5.7 and $4.9 million, and spare parts inventory amounted to $8.9, $12.8 and $8.8 million, respectively.

Amounts Recoverable Under Terms of the Power Sales Agreements

Billings to Project Participants are designed to recover costs in accordance with the PSAs to provide for debt service, operating funds and reserve requirements. Expenses are reflected in the Statements of Operations in accordance with GAAP. 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 $227.8, $245.1 and $228.8 million and have cumulative billings in excess of costs which total $8.4, $6.5 and $5.1 million at December 31, 2000, 1999 and 1998, respectively. These amounts have been netted in the Statements of Financial Position.

The December 31, 2000, 1999 and 1998 balances of $219.4, $238.6 and $223.7 million, respectively, reflects the Statements of Operations net decrease (increase) of $16.8, ($11.1) and ($16.3) million for the years then ended and the change in net unrealized gain (loss) on securities available for sale of $2.4, ($3.8) and $.9 million for 2000, 1999 and 1998, respectively.

Nuclear Decommissioning Trusts

MMWEC maintains external trust funds, as required by Nuclear Regulatory Commission and state regulations, to provide for the decommissioning activities of Millstone Unit 3 and Seabrook Station. The December 31, 2000 Millstone Unit 3 and Seabrook Station balances of $9.1 and $12.7 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 $31.1 and $70.6 million, respectively.

Depreciation

Electric Plant In Service is depreciated using the straight-line method. The aggregate annual provisions for depreciation for 2000, 1999 and 1998 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.

(3) Revenues and Unbilled Revenues

Revenues include electric sales for resale provided through MMWEC's power supply program which consists of billings under the PSAs, Power Purchase Agreements (PPAs) and related power brokering arrangements. MMWEC also 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)	2000	1999	1998
Revenues			
Electric sales for resale	$261,438	$230,570	$225,690
Service	1,187	1,524	1,426
Millstone Unit 3 Settlement	12,595	—	—
Other	1,120	—	833
Total Revenues	$276,340	$232,094	$227,949

In August 2000, MMWEC executed a settlement agreement and release of its claims in all litigation proceedings against the lead owners of Millstone Unit 3 associated with the unit's shutdown of 1996, pursuant to which MMWEC received approximately $12.6 million and other consideration. MMWEC also agreed to waive its right of first refusal under the Millstone Unit 3 Sharing Agreement. The $12.6 million settlement was refunded to the Project Participants and is a reduction to electric sales for resale.

In August 2000, MMWEC received $1.1 million in satisfaction of a judgment concerning water rates charged to the Stony Brook Energy Center. In 1998, MMWEC received the final payment for the Comprehensive Settlement Agreement with Public Service Company of New Hampshire (PSNH), which was agreed to in 1988, which among other considerations provided for PSNH to pay MMWEC $2 million per year for eight years upon commercial operation of Seabrook. All of these payments are included in other revenues.

(4) Debt

Power Supply System Revenue Bonds

MMWEC debt, other than obligations maturing within one year, require Massachusetts Department of Telecommunications and Energy's (DTE) 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 common pledge of all the revenues derived by MMWEC under the terms of all 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.

In January 2001, MMWEC issued $94.2 million of 2001 Series A and $1.6 million of Series B refunding bonds which were utilized to purchase for cancellation $95.4 million of portions of the 1992 Series A, 1992 Series C, 1992 Series E, 1993 Series A, 1994 Series A and 1994 Series B bonds. The information in the following table has not been adjusted for the refunding as the effect is not material.

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, 2000	1999	1998
	1987 Series A	8.9%	$ 6,310	$ 7,110	$ 7,850
	1992 Series A	7.0%	87,170	89,805	92,285
	1992 Series B	7.0%	168,070	174,470	180,495
	1992 Series C	6.9%	52,775	54,295	55,740
	1992 Series D	6.3%	72,655	75,395	77,990
	1992 Series E	6.0%	66,365	75,735	84,615
	1993 Series A	5.3%	313,215	329,100	343,390
	1994 Series A	5.3%	112,270	113,130	113,670
	1994 Series B	5.1%	153,240	161,445	169,100
	1994 Series C	Variable	97,600	97,600	97,600
Bonds Payable			1,129,670	1,178,085	1,222,735
Less: Current Maturities			(50,580)	(47,870)	(44,650)
Total Long-Term Debt			$1,079,090	$1,130,215	$1,178,085

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: 2001 - $50.6 million; 2002 - $53.4 million; 2003 - $56.6 million; 2004 – $60.0 million and 2005 - $63.3 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.

In March 2000, the DTE approved MMWEC's petition for authority to refund all of the debt outstanding under the GBR and authorized the issuance by MMWEC of up to $1.59 billion of refunding bonds. The DTE also authorized the maintenance and use by MMWEC of $733 million of previously authorized, but unused, refunding authority. As of March 2, 2001, MMWEC has taken no action with respect to these approvals.

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% which expired 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, 2000, 1999, 1998 and prior years, MMWEC met the GBR debt service coverage requirements for the applicable MMWEC Projects.

	Contract Year Ended June 30,		
(In Thousands)	2000	1999	1998
Debt Service Coverage:			
Revenues	$180,789	$185,786	$191,245
Other Billings	577	574	576
Reserve and Contingency Fund Billings	11,227	11,076	11,626
Total	192,593	197,436	203,447
Less: Operating & Maintenance Expenses	(69,099)	(75,604)	(75,566)
Available Revenues Net of Expenses	$123,494	$121,832	$127,881
Debt Service Requirement	$112,267	$110,756	$116,255
Coverage (110% Required)	110%	110%	110%

Notes Payable

MMWEC maintains a $5 million revolving line of credit to temporarily finance certain power purchases made by MMWEC for resale under power purchase contracts. Borrowings outstanding under the line of credit were $50,000, $82,000 and $0 at December 31, 2000, 1999 and 1998. During 2000, 1999 and 1998 the maximum outstanding balance under the line of credit was $903,000, $2,385,000 and $90,000, respectively. Interest charged on borrowings under the line of credit is at minus one percent of the bank's prime rate (8.5% at December 31, 2000). 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 of 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, 2000 commercial paper notes outstanding balance was $28 million at an interest rate of 4%.

(5) 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 $2.4, $2.6 and $2.5 million in 2000, 1999 and 1998, respectively. The following is a summary of Projects included in Electric Plant In Service and MMWEC's share of capability.

	Facility and MMWEC		Amounts as of December 31,		
(In Thousands)	Share of Capability (MW)		2000	1999	1998
Peaking Project	Stony Brook	170.0	$ 56,399	$ 56,380	$ 56,338
Intermediate Project	Stony Brook	319.5	151,691	151,337	153,968
Wyman Project	W.F. Wyman No. 4	22.7	7,341	7,341	7,365
Nuclear Project No. 3	Millstone Unit 3	36.8	130,400	130,048	129,814
Nuclear Mix No. 1	Millstone Unit 3	18.4	51,694	51,517	51,400
Nuclear Mix No. 1	Seabrook Station	1.9	8,633	8,616	8,599
Nuclear Project No. 4	Seabrook Station	49.8	260,092	259,630	259,204
Nuclear Project No. 5	Seabrook Station	12.6	71,155	71,038	70,930
Project No. 6	Seabrook Station	69.0	502,328	501,688	501,098
			$1,239,733	$1,237,595	$1,238,716

In August 2000, all of the joint owners of Millstone Unit 3, except MMWEC and one other joint owner, entered into purchase and sale agreements with Dominion Resources, Inc., pursuant to which Dominion agreed to purchase the other joint owners' collective 93.47% ownership interest in Millstone Unit 3.

MMWEC has an 11.6% ownership interest in the Seabrook Station nuclear generating unit and it is anticipated that certain other joint owners of Seabrook, not including MMWEC, intend to sell their ownership interest in Seabrook through a bid process commencing in 2001.

(6) Investments and Deposits

All bank deposits, which amounted to $727,000 at December 31, 2000, 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 $12.7 million during 2000 due to seasonal cash flows, and the timing of daily cash receipts. At December 31, 2000, 1999 and 1998 investments are classified as available for sale and reported at fair value with unrealized gains of $1.4, $.7 and $2.7 million, respectively, and unrealized losses of $88,000, $1.8 million and $47,000 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, 2000, 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:

(In Thousands)	2000		1999		1998	
Type of Investment	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value
Repurchase Agreements	$ —	$ —	$ 3,899	$ 3,899	$ —	$ —
Other Investments:						
U.S. Treasury bills	23,950	24,300	22,457	22,985	20,825	21,524
U.S. Treasury notes	63,533	63,924	77,146	75,913	79,077	80,866
U.S. Agency bonds	85,753	86,241	29,142	28,651	—	—
Municipal bonds	1,355	1,368	8,199	8,228	7,089	7,276
U.S. Agency discount notes	76,224	76,250	102,519	102,565	133,010	133,000
Total Other Investments	250,815	252,083	239,463	238,342	240,001	242,666
Total Investments	$250,815	$252,083	$243,362	$242,241	$240,001	$242,666

During 2000, 1999 and 1998, the proceeds from the sale of available for sale securities were $89.0 million, $33.1 million and $0 resulting in gross realized gains of $20,000, $70,000 and $0 and gross realized losses of $168,000, $66,000 and $0, 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, 2000, 1999 and 1998 were 497, 530 and 347 days, respectively.

Due to seasonal cash flows during 2000, 1999 and 1998, 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.

(7) 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:

	2000		1999		1998	
(In Thousands)	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Financial Assets:						
Investments	$252,083	$252,083	$242,241	$242,241	$242,666	$242,666
Decommissioning Trusts	21,882	24,190	18,142	20,925	14,713	17,310
Interest Rate Protection Agreement	41	12	152	150	263	75
Financial Liabilities:						
Long-Term Debt	1,079,090	1,102,240	1,130,215	1,135,393	1,178,085	1,229,525
Unrecognized Financial Instruments:						
Debt Service Forward Delivery Agreement	—	899	—	891	—	3,070

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.

(8) 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.

(9) 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 2000, 1999 and 1998 and projected salary increases of 4.0% in 2000, 1999 and 1998. The Pension Benefit Obligation for both plans is as follows:

	Amounts as of January 1,		
(In Thousands)	2000	1999	1998
Retirees currently receiving benefits and terminated employees not yet receiving benefits	$ 983	$1,018	$ 582
Current Employees:			
Vested	3,811	3,374	3,891
Non-vested	2,709	2,536	2,775
Total Pension Benefit Obligation	7,503	6,928	7,248
Net assets available for benefits, at market	7,821	7,735	7,264
Under (Over) funded Pension Benefit Obligation	$ (318)	$ (807)	$ (16)

The following is provided in accordance with FAS 132 "Employers' Disclosures about Pensions and Other Post Retirement Benefits" for the years 2000 and 1999 (1998 information is unavailable).

	Amounts as of December 31	
	2000	1999
Changes in benefit obligation		
Benefit obligation at beginning of year	$7,333	$7,359
Service cost	386	365
Interest cost	512	470
Actuarial (gain)/loss	170	(430)
Benefits paid	(397)	(431)
Benefit obligation at end of year	$8,004	$7,333
Change in plan assets		
Fair value of plan assets at beginning of year	$7,821	$7,735
Actual return on plan assets	144	6
Employer contribution	588	542
Benefits paid, including expenses	(434)	(462)
Fair value of plan assets at end of year	$8,119	$7,821
Funded Status	$ 115	$ 488
Unrecognized net actuarial (gain)/loss	1,278	573
Unrecognized prior service cost	161	185
Unrecognized transition (asset)/obligation	88	104
(Accrued)/prepaid pension cost	$1,642	$1,350
Components of net periodic benefit cost		
Service cost	$ 386	$ 365
Interest cost	511	470
Expected return on plan assets	(673)	(662)
Amortization of transition (asset)/obligation	15	15
Amortization of prior service cost	24	24
Recognized net actuarial loss	33	—
Net periodic benefit cost	$ 296	$ 212

Annual contributions to the pension plans recorded as pension expense were $588,000, $541,000 and $498,000, for the years ended December 31, 2000, 1999 and 1998, respectively. These amounts were billed to PSAs, PPAs and Service Agreement and are included in Other Operating Expense in the Statements of Operations. 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 2000, 1999 and 1998. 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 $104,000, $99,000 and $99,000 while the employees contributed $177,000, $177,000 and $169,000 during the years ended December 31, 2000, 1999 and 1998, respectively.

(10) 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 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 enacted legislation to restructure the electric utility industry. MMWEC and the municipal light departments are not specifically subject 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 $9.5 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 $9.3 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 $.4 and $1.4 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 2000 or outstanding as of December 31, 2000.

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.

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, 2000, 1999 and 1998.

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 2, 2001

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

PROJECT STATEMENTS OF FINANCIAL POSITION

Year Ended December 31, 2000

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
ASSETS				
Electric Plant				
In Service	$ 2,415	$ 60,327	$130,400	$260,092
Accumulated Depreciation	(2,154)	(25,597)	(57,373)	(93,219)
	261	34,730	73,027	166,873
Nuclear Fuel-Net of Amortization	—	1,203	2,157	3,301
Total Electric Plant	261	35,933	75,184	170,174
Special Funds				
Bonds Fund				
Interest, Principal and Retirement Account	—	3,449	3,751	8,261
Reserve Account	—	6,977	11,537	14,332
Reserve and Contingency Fund	—	3,521	4,380	5,806
Revenue Fund	—	6,696	7,898	13,431
Working Capital Funds	18,373	—	—	—
	18,373	20,643	27,566	41,830
Current Assets				
Cash and Temporary Investments	912	—	—	1
Accounts Receivable	8,347	19	60	17
Unbilled Revenues	12,204	—	—	—
Inventories	—	63	—	1,685
Advances to (from) Projects	1,855	(60)	(181)	(192)
Prepaid Expenses	494	940	1,777	1,205
Total Current Assets	23,812	962	1,656	2,716
Total Special Funds and Current Assets	42,185	21,605	29,222	44,546
Deferred Charges				
Amounts Recoverable (Payable) Under Terms of the Power Sales Agreements	27,635	57,203	83,852	3,734
Unamortized Debt Discount and Expenses	283	1,582	2,539	4,213
Nuclear Decommissioning Trusts	—	3,230	6,082	4,765
Other	45	135	311	701
	27,963	62,150	92,784	13,413
	$70,409	$119,688	$197,190	$228,133
LIABILITIES				
Long-Term Debt				
Bonds Payable	$ —	$104,395	$177,450	$204,925
Current Liabilities				
Current Maturities of Long-Term Debt	—	6,070	7,220	7,190
Commercial Paper	28,025	—	—	—
Notes Payable	50	—	—	—
Accounts Payable	2,600	164	181	1,928
Accrued Expenses	13,764	2,407	4,403	5,492
Member and Participant Advances and Reserves	25,970	3,363	1,745	3,698
	70,409	12,004	13,549	18,308
Deferred Credits	—	3,289	6,191	4,900
	$70,409	$119,688	$197,190	$228,133

Schedule I

Nuclear Proj. 5	Project No. 6	Peaking	Intermediate	Wyman	Hydro Quebec Phase II	Total
$ 71,155	$ 502,328	$ 56,399	$ 151,691	$ 7,341	$ —	$1,242,148
(25,590)	(182,397)	(40,490)	(113,145)	(4,776)	—	(544,741)
45,565	319,931	15,909	38,546	2,565	—	697,407
838	4,609	—	—	—	—	12,108
46,403	324,540	15,909	38,546	2,565	—	709,515
2,676	19,404	2,630	6,421	304	—	46,896
4,470	33,029	2,441	6,322	288	—	79,396
1,523	8,852	879	1,650	288	—	26,899
3,625	22,254	6,219	17,305	1,656	—	79,084
—	—	—	—	—	(20)	18,353
12,294	83,539	12,169	31,698	2,536	(20)	250,628
—	2	—	—	—	—	915
4	23	391	649	193	102	9,805
—	—	—	—	—	—	12,204
427	2,334	1,882	7,059	229	—	13,679
(56)	(296)	450	(1,485)	(35)	—	—
307	1,675	14	21	1	—	6,434
682	3,738	2,737	6,244	388	102	43,037
12,976	87,277	14,906	37,942	2,924	82	293,665
6,406	45,861	(6,786)	3,122	(801)	(831)	219,395
1,655	9,010	91	721	(5)	—	20,089
1,206	6,599	—	—	—	—	21,882
176	988	174	4,716	13	813	8,072
9,443	62,458	(6,521)	8,559	(793)	(18)	269,438
$ 68,822	$ 474,275	$ 24,294	$ 85,047	$ 4,696	$ 64	$1,272,618
$ 62,380	$ 434,800	$ 19,095	$ 72,595	$ 3,450	$ —	$1,079,090
2,255	14,760	3,925	8,780	380	—	50,580
—	—	—	—	—	—	28,025
—	—	—	—	—	—	50
485	2,694	33	652	544	4	9,285
1,393	7,643	261	393	95	—	35,851
1,069	7,592	980	2,627	227	60	47,331
5,202	32,689	5,199	12,452	1,246	64	171,122
1,240	6,786	—	—	—	—	22,406
$ 68,822	$ 474,275	$ 24,294	$ 85,047	$ 4,696	$ 64	$1,272,618

PROJECT STATEMENTS OF OPERATIONS

Year Ended December 31, 2000

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
Revenues	$78,632	$16,279	$26,438	$30,059
Interest Income	1,651	1,353	1,909	2,698
Total Revenues and Interest Income	$80,283	$17,632	$28,347	$32,757
Operating and Service Expenses:				
Fuel Used in Electric Generation	$ —	$ 750	$ 1,378	$ 1,595
Purchased Power	68,708	—	—	—
Other Operating	1,371	4,022	7,241	7,846
Maintenance	13	773	1,358	2,441
Depreciation	22	1,970	4,151	9,455
Taxes Other Than Income	3	425	781	882
	70,117	7,940	14,909	22,219
Interest Expense:				
Interest Charges	1,539	5,704	10,116	12,194
Interest Charged to Projects During Construction	—	(5)	(11)	(36)
	1,539	5,699	10,105	12,158
Total Operating Costs and Interest Expense	71,656	13,639	25,014	34,377
Other	—	—	—	(16)
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements	8,627	3,993	3,333	(1,604)
	$80,283	$17,632	$28,347	$32,757

** 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
$8,569	$56,530	$9,079	$46,826	$3,432	$496	$276,340
803	5,466	838	2,377	164	68	17,327
$9,372	$61,996	$9,917	$49,203	$3,596	$564	$293,667
$ 406	$ 2,241	$1,812	$21,523	$2,136	$ —	$ 31,841
—	—	—	—	—	533	69,241
2,042	11,197	1,409	4,987	*726	—	40,841
617	3,380	1,043	7,237	—	—	16,862
2,583	18,170	2,276	6,347	231	—	45,205
224	1,221	390	1,078	176	—	5,180
5,872	36,209	6,930	41,172	3,269	533	209,170
3,858	28,483	1,372	4,425	190	—	67,881
(10)	(60)	—	—	—	—	(122)
3,848	28,423	1,372	4,425	190	—	67,759
9,720	64,632	8,302	45,597	3,459	533	276,929
(2)	(25)	—	—	—	—	(43)
(346)	(2,611)	1,615	3,606	137	31	16,781
$9,372	$61,996	$9,917	$49,203	$3,596	$564	$293,667

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

PROJECT STATEMENTS OF CASH FLOWS

Year Ended December 31, 2000

(In Thousands)	Service	Nuclear Mix 1	Nuclear Proj. 3	Nuclear Proj. 4
Cash flows from operating activities:				
Total Revenues and Interest Income	$ 80,283	$ 17,632	$ 28,347	$ 32,757
Total Costs and Expenses, net	(71,656)	(13,639)	(25,014)	(34,361)
Adjustments to arrive at net cash provided by operating activities:				
Depreciation and Decommissioning	22	2,227	4,609	10,164
Amortization	113	773	1,370	1,691
Change in current assets and liabilities:				
Accounts Receivable	(2,411)	16	(20)	120
Unbilled Revenues	(8,904)	—	—	—
Inventories	—	(4)	—	(107)
Prepaid Expenses	72	(73)	(150)	68
Accounts Payable	1,583	(161)	(259)	605
Accrued Expenses and Other	8,582	571	929	1,396
Member and Participant Advances and Reserves	(690)	1,603	1,433	1,386
Net cash provided by (used for) operating activities	6,994	8,945	11,245	13,719
Cash flows from investing activities:				
Construction Expenditures and Purchases of Nuclear Fuel	(130)	(929)	(1,656)	(2,630)
Interest Charged to Projects During Construction	—	(5)	(11)	(36)
Net (Increase) Decrease in Special Funds	1,620	(2,116)	(2,460)	(3,741)
Change in net Unrealized Gain on Special Funds	109	194	253	463
Decommissioning Trust Payments	—	(411)	(747)	(979)
Other	127	147	271	269
Net cash provided by (used for) investing activities	1,726	(3,120)	(4,350)	(6,654)
Cash flows from financing activities:				
Payments for Principal of Long-Term Debt and Commercial Paper	(8,740)	(5,825)	(6,895)	(7,065)
Payments for Commercial Paper Issue Costs	(72)	—	—	—
Change in Notes Payable	(32)	—	—	—
Net cash used for financing activities	(8,844)	(5,825)	(6,895)	(7,065)
Net decrease in cash and temporary investments	(124)	—	—	—
Cash and Temporary Investments at Beginning of Year	1,036	—	—	1
Cash and Temporary Investments at End of Year	$ 912	$ —	$ —	$ 1
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 1,306	$ 5,461	$ 9,741	$ 11,695

Nuclear Proj. 5	Project No. 6	Peaking	Intermediate	Wyman	Hydro Quebec Phase II	Total
$ 9,372	$ 61,996	$ 9,917	$ 49,203	$ 3,596	$ 564	$ 293,667
(9,718)	(64,607)	(8,302)	(45,597)	(3,459)	(533)	(276,886)
2,763	19,152	2,260	6,285	231	—	47,713
487	2,673	40	206	1	—	7,354
31	166	(391)	(608)	(126)	(2)	(3,225)
—	—	—	—	—	—	(8,904)
(28)	(148)	1,630	3,550	(67)	—	4,826
17	94	(1)	1	8	—	36
145	831	(1,646)	(2,031)	361	(3)	(575)
358	1,959	70	(1,449)	114	(29)	12,501
434	1,651	(691)	(4,554)	(117)	(39)	416
3,861	23,767	2,886	5,006	542	(42)	76,923
(666)	(3,642)	(19)	(496)	—	—	(10,168)
(10)	(60)	—	—	—	—	(122)
(1,205)	(5,799)	781	3,532	(198)	—	(9,586)
127	951	71	205	16	—	2,389
(248)	(1,355)	—	—	—	—	(3,740)
66	373	1	143	—	—	1,397
(1,936)	(9,532)	834	3,384	(182)	—	(19,830)
(1,925)	(14,235)	(3,720)	(8,390)	(360)	—	(57,155)
—	—	—	—	—	—	(72)
—	—	—	—	—	—	(32)
(1,925)	(14,235)	(3,720)	(8,390)	(360)	—	(57,259)
—	—	—	—	—	(42)	(166)
—	2	—	—	—	42	1,081
$ —	$ 2	$ —	$ —	$ —	$ —	$ 915
$ 3,671	$ 27,463	$ 1,300	$ 4,182	$ 185	$ —	$ 65,004

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.

MMWEC

Annual Report 2001

New England Power Company

National Grid

New England Power Company

25 Research Drive
Westborough, Massachusetts 01582

Directors

(As of April 1, 2001)

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

Peter G. Flynn
President of the Company

Michael E. Jesanis
Vice President of the Company and Executive Vice President of National Grid USA

Lawrence J. Reilly
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of National Grid USA

Robert G. Powderly
Vice President of National Grid USA

Terry L. Schwennesen
Vice President of the Company

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 April 1, 2001)

Peter G. Flynn
President of the Company

Michael E. Jesanis
Vice President of the Company and Executive Vice President of National Grid USA

Lawrence J. Reilly
Vice President and General Counsel of the Company and Senior Vice President, General Counsel, and Secretary of National Grid USA

Marc F. Mahoney
Vice President of the Company and of certain affiliates

John F. Malley
Vice President of the Company

James S. Robinson
Vice President of the Company

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

Terry L. Schwennesen
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, President of certain affiliates, Vice President of an affiliate, and Vice President, Chief Financial Officer, and Treasurer of National Grid USA

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

Geraldine M. Zipser
Assistant Clerk of the Company and of certain affiliates, Secretary or Clerk of certain affiliates, and Assistant Secretary of an affiliate

Patricia C. Easterly
Assistant Treasurer of the Company and Treasurer of an affiliate

Nancy B. Kellogg
Assistant Treasurer of the Company and of certain affiliates

Kwong O. Nuey
Controller of the Company and of certain affiliates and Vice President of an affiliate

Transfer Agent, Dividend Paying Agent, and Registrar of Preferred Stock
Fleet National Bank, 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 all these states (except Connecticut), 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 facilities are part of National Grid USA's transmission operations, which are represented under the name 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 of cash flows present fairly, in all material respects, the financial position of New England Power Company at March 31, 2001 and 2000, and the results of its operations and its cash flows for of the year ended March 31, 2001, the three month period ended March 31, 2000, and the years ended December 31, 1999 and 1998, in conformity with accounting principles generally accepted in the United States of America. 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 of America, 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 our opinion.

PricewaterhouseCoopers LLP
Boston, Massachusetts

April 25, 2001, except for the last paragraph
of the Seabrook 1 section of Note D,
as to which the date is May 22, 2001,
and the fourth paragraph of Note C,
as to which the date is June 8, 2001

New England Power Company

Statements of Income

(In thousands)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Operating revenue, principally from affiliates	**$656,272**	$134,564	$167,177	$596,341	$1,218,340
Operating expenses:					
Fuel for generation	**14,342**	3,548	3,058	12,803	223,828
Purchased electric energy:					
Contract termination and nuclear unit shutdown charges	**214,948**	47,405	46,873	187,777	97,469
Other	**91,844**	14,682	11,111	56,731	302,367
Other operation	**69,624**	15,760	19,210	70,936	155,065
Maintenance	**31,748**	4,320	5,766	28,536	60,239
Depreciation and amortization	**78,762**	16,962	40,367	103,080	99,924
Taxes, other than income taxes	**22,343**	5,561	5,634	20,282	48,492
Income taxes	**44,946**	9,641	13,100	37,633	73,594
Total operating expenses	**568,557**	117,879	145,119	517,778	1,060,978
Operating income	**87,715**	16,685	22,058	78,563	157,362
Other income:					
Allowance for equity funds used during construction	**276**	(393)	588	1,958	633
Equity in income of nuclear power companies	**6,703**	862	515	2,939	5,284
Amortization of goodwill	**(17,905)**	(366)	-	-	-
Other income (expense), net	**3,559**	1,850	434	2,087	118
Operating and other income	**80,348**	18,638	23,595	85,547	163,397
Interest:					
Interest on long-term debt	**17,834**	3,749	3,143	14,052	30,775
Other interest	**4,883**	853	240	1,003	10,688
Allowance for borrowed funds used during construction	**(669)**	(426)	(133)	(522)	(961)
Total interest	**22,048**	4,176	3,250	14,533	40,502
Net income	**$ 58,300**	$ 14,462	$ 20,345	$ 71,014	$ 122,895

Statements of Retained Earnings

(In thousands)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Retained earnings at beginning of period	**$ 1,415**	$ 27,287	$204,603	$ 204,603	$ 407,630
Net income	**58,300**	14,462	20,345	71,014	122,895
Dividends declared on cumulative preferred stock	**(91)**	(24)	(24)	(94)	(1,230)
Dividends declared on common stock, $-0-, $6.66, $-0-, $66.69, and $20.25, per share, respectively	**-**	(24,098)	-	(241,415)	(130,610)
Gain on redemption of preferred stock	**21**	-	-	264	(264)
Repurchase of common stock	**-**	-	(7,085)	(7,085)	(193,818)
Purchase accounting adjustment	**-**	(16,212)	-	-	-
Acquisition adjustment	**465**	-	-	-	-
Retained earnings at end of period	**$60,110**	$ 1,415	$217,839	$ 27,287	$ 204,603

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

New England Power Company
Balance Sheets

(In thousands)	At March 31, 2001	At March 31, 2000
Assets		
Utility plant, at original cost	$ 846,935	$1,318,026
Less accumulated provisions for depreciation and amortization	320,238	854,309
	526,697	463,717
Construction work in progress	34,946	35,730
Net utility plant	561,643	499,447
Goodwill, net of amortization	338,188	333,771
Investments:		
Nuclear power companies, at equity (Note D-1)	46,474	45,966
Decommissioning trust funds (Note D-2)	16,331	36,279
Nonutility property and other investments	14,374	7,490
Total investments	77,179	89,735
Current assets:		
Cash and temporary cash investments (including $22,075 and $37,820 with affiliates)	22,360	226,921
Accounts receivable:		
Affiliated companies	61,191	72,780
Others	89,483	48,139
Fuel, materials, and supplies, at average cost	6,289	10,345
Prepaid and other current assets	2,051	25,377
Regulatory assets - purchased power obligations and accrued Yankee nuclear plant costs	158,578	82,698
Total current assets	339,952	466,260
Regulatory assets (Note C)	1,522,089	1,203,090
Deferred charges and other assets	50,170	37,271
	$2,889,221	$2,629,574
Capitalization and Liabilities		
Capitalization:		
Common stock, par value $20 per share,		
Authorized - 6,449,896 shares		
Outstanding - 3,619,896 shares	$ 72,398	$ 72,398
Other paid-in capital (Note J)	731,974	582,983
Retained earnings	60,110	1,415
Unrealized gain (loss) on securities, net	(145)	-
Total common equity	864,337	656,796
Cumulative preferred stock, par value $100 per share (Note H)	1,436	1,567
Long-term debt	410,279	371,773
Total capitalization	1,276,052	1,030,136
Current liabilities:		
Short-term debt	-	38,500
Accounts payable (including $25,287 and $26,993 to affiliates)	66,017	51,584
Accrued liabilities:		
Taxes	39,451	2,394
Interest	1,489	1,900
Purchased power obligations and accrued Yankee nuclear plant costs	158,578	82,698
Other accrued expenses (Note G)	7,621	10,879
Dividends payable	22	256,487
Total current liabilities	273,178	444,442
Deferred federal and state income taxes	272,304	176,351
Unamortized investment tax credits	9,312	16,733
Accrued Yankee nuclear plant costs (Note D-2)	172,340	261,145
Purchased power obligations	636,848	611,802
Other reserves and deferred credits	249,187	88,965
Commitments and contingencies (Note D)		
	$2,889,221	$2,629,574

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

New England Power Company

Statements of Cash Flows

(In thousands)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	1999 (unaudited)	Year Ended December 31, 1999	1998
Operating activities:					
Net income	**$ 58,300**	$ 14,462	$ 20,345	$ 71,014	$ 122,895
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	**85,123**	18,799	42,170	108,789	104,331
Amortization of goodwill	**17,905**	366	-	-	-
Deferred income taxes and investment tax credits, net	**(11,480)**	(2,908)	5,726	14,111	(226,722)
Allowance for funds used during construction	**(945)**	(33)	(720)	(2,480)	(1,594)
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)
Changes in assets and liabilities, net of effects of acquisition:					
Decrease (increase) in accounts receivable, net	**(7,914)**	(3,174)	37,890	22,706	130,914
Decrease (increase) in fuel, materials, and supplies	**4,160**	(874)	648	(251)	(10,270)
Decrease (increase) in regulatory assets	**152,533**	60,044	82,801	166,730	(1,071,524)
Decrease (increase) in prepaid and other current assets	**26,501**	13,938	6,154	(17,746)	(8,778)
Increase (decrease) in accounts payable	**(813)**	(11,628)	(81,950)	(99,148)	(31,761)
Increase (decrease) in purchased power contract obligations	**(77,039)**	(16,947)	(36,903)	(128,931)	832,668
Increase (decrease) in other current liabilities	**30,822**	(7,787)	(11,147)	(14,575)	5,037
Increase (decrease) in other non-current liabilities	**(147,847)**	20,349	(5,661)	45,483	(108,896)
Other, net	**73,202**	(49,869)	(40,946)	(87,277)	298,141
Net cash provided by (used in) operating activities	**$ 202,508**	$ 34,738	$ 18,407	$ 74,953	$ (413,049)
Investing activities:					
Proceeds from sale of generating assets	**$ -**	$ -	$ -	$ -	$ 1,688,863
Plant expenditures, excluding allowance for funds used during construction	**(56,558)**	(11,890)	(13,739)	(56,887)	(64,446)
Other investing activities	**(3,270)**	(271)	(20)	(4,411)	(5,474)
Net cash provided by (used in) investing activities	**$ (59,828)**	$(12,161)	$(13,759)	$ (61,298)	$ 1,618,943

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

New England Power Company

Statements of Cash Flows – (continued)

(In thousands)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Financing activities:					
Capital contribution from parent	**$ -**	$ -	$ -	$ -	$ 34,881
Dividends paid on common stock	**(256,463)**	-	-	(9,050)	(166,084)
Dividends paid on preferred stock	**(93)**	-	(24)	(118)	(1,206)
Changes in short-term debt	**(38,500)**	-	-	38,500	(111,250)
Long-term debt - issues	**38,500**	-	-	-	-
Long-term debt - retirements	**(90,575)**	-	-	-	(328,000)
Repurchase of common shares	**-**	-	(18,056)	(18,056)	(417,960)
Preferred stock - retirements	**(110)**	-	-	-	(38,505)
Net cash provided by (used in) financing activities	**$(347,241)**	$ -	$(18,080)	$ 11,276	$(1,028,124)
Net increase (decrease) in cash and cash equivalents	**$(204,561)**	$ 22,577	$(13,432)	$ 24,931	$ 177,770
Cash and cash equivalents at beginning of period	**226,921**	204,344	179,413	179,413	1,643
Cash and cash equivalents at end of period	**$ 22,360**	$226,921	$165,981	$204,344	$ 179,413
Supplementary Information:					
Interest paid less amounts capitalized	**$ 18,296**	$ 5,322	$ 2,042	$ 11,849	$ 43,419
Federal and state income taxes paid (refunded)	**$ (3,233)**	$ (15)	$ 11,321	$ 55,134	$ 282,076
Dividends received from investments at equity	**$ 13,986**	$ 1,129	$ 1,730	$ 5,243	$ 6,571

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

New England Power Company

Financial Review

Merger with National Grid

On March 22, 2000, the merger of New England Electric System (NEES) and 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) maintained its existing name and remained a wholly owned subsidiary of National Grid USA. The merger was accounted for by the purchase method, the application of which, including the recognition of goodwill, was pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $1.7 billion, of which the Company was allocated approximately $348 million. This amount was determined pursuant to a study conducted by an independent third party and is being amortized over 20 years. Amortization expense is approximately $17.4 million annually.

The purchase accounting method requires the revaluation of assets and liabilities to their fair value. This revaluation resulted in an adjustment to the Company's pension and postretirement benefit accounts in the amount of approximately $61 million, with an offsetting net credit to a regulatory liability account (see Note E).

Acquisition of EUA

The acquisition of Eastern Utilities Associates (EUA) by National Grid USA was completed on April 19, 2000 for $642 million. On May 1, 2000, Montaup Electric Company (Montaup), formerly a subsidiary of EUA, was merged into the Company.

The acquisition of EUA was accounted for by the purchase method, the application of which, including the recognition of goodwill, has been pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill recognized in this transaction was approximately $402 million, of which the Company was allocated approximately $8 million. This amount was determined pursuant to a study conducted by an independent third party and is being amortized over 20 years. Amortization expense is approximately $0.4 million annually.

The purchase accounting method requires the revaluation of assets and liabilities to their fair value. This revaluation resulted in an adjustment to the Company's pension and postretirement benefit accounts in the amount of approximately $3 million, with an offsetting net credit to a regulatory liability account (see Note E).

As a result of the acquisition, Montaup's balance sheet accounts were incorporated into the financial statements of the Company as of May 1, 2000. Listed below are the significant account balances incorporated.

	May 1, 2000 balance (In thousands)
Assets	
Utility plant, at original cost	$227,114
Accumulated provisions for depreciation and amortization	$ (92,093)
Regulatory assets (current and long-term)	$547,412
Liabilities	
Other paid-in capital	$135,444
Deferred federal and state income taxes	$104,860
Accrued Yankee nuclear plant costs	$ 46,030
Purchased power obligations (current and long-term)	$176,257
Other reserves and deferred credits	$174,942

The accompanying statements of operations do not include any revenues or expenses related to Montaup prior to the companies' merger on May 1, 2000.

New England Power Company

Regulatory Environment and Accounting Implications

Under 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 with which it has settlement agreements through contract termination charges (CTC). The Company's retail distribution affiliates recover CTC-related costs through delivery charges to distribution customers. The recovery of the Company's stranded costs (including the Montaup share) is divided into several categories. The Company's unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets were fully recovered through the CTC by the end of 2000 and earned a return on equity (ROE) averaging 9.7 percent. The Montaup share of unrecovered costs associated with generating plants and most regulatory assets will be fully recovered through the CTC by the end of 2009. 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 ROE. Until such time as the Company divests its operating nuclear interests, 80 percent of the revenues and operating costs related to the units will be allocated to customers through the CTC, with shareholders being allocated the balance.

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. Similar to the Company, Montaup also transferred its purchased power obligations as part of the divestiture and in return agreed to make fixed monthly payments. The aggregate fixed monthly payments, including the Montaup share, average $11.3 million per month through December 2009 toward the above-market cost of those contracts. The liability relating to purchased power obligations, which is also reflected in regulatory assets, represents the net present value of these fixed monthly payments. At March 31, 2001, the net present value is approximately $786 million. 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 $453 million), which were separate from the $786 million figure referred to above.

Prior to divesting substantially all of its nonnuclear generation business in 1998, the Company was the wholesale supplier of the electric energy requirements to its retail distribution affiliates as well as unaffiliated customers. The Company's all-requirements contracts with its affiliated distribution companies, as well as with some unaffiliated customers, were generally terminated pursuant to settlement agreements and tariff provisions in 1998. However, the Company remains obligated to provide transition power supply service to new customer load in Rhode Island at the standard offer price, but does not have a regulatory agreement that necessarily allows full recovery of the costs of such standard offer power. Consequently, the Company is at risk for the difference between the actual cost of serving this load and the revenue received from this obligation. The standard offer rate that the Company charges for continuing to meet this obligation increased from 3.5 cents per kilowatthour (kWh) in 1999 to 3.8 cents per kWh effective January 1, 2000. The standard offer rate is also subject to a rolling twelve-month fuel index adjustment factor, which increased the rate by an additional 0.121 cents per kWh beginning in April 2000 up to 2.404 cents per kWh by March 2001. The Company meets this obligation through a combination of generation from some of its remaining generation sources, as well as by periodically procuring power at market prices. Over time, the Company cannot predict whether the resulting revenues will be sufficient to cover the costs of procuring such power. For the year ended March 31, 2001, the Company's losses from this obligation were approximately $5 million.

New England Power Company

In a December 15, 2000 Order, the Federal Energy Regulatory Commission (FERC) rejected the Independent System Operator-New England's (ISO New England) proposed $0.17 per kW-month Installed Capacity (ICAP) deficiency charge and reinstated an administratively-determined deficiency charge of $8.75 per kW-month, retroactive to August 1, 2000. Several parties, including the Company, filed motions requesting rehearing and stay of the FERC's order. On January 10, 2001, the FERC granted these motions. On March 6, 2001, the FERC reversed its earlier order by allowing ISO New England's previously proposed ICAP rate of $0.17 per kW-month to be effective from August 1, 2000 through March 31, 2001. Effective April 1, 2001, the FERC ordered an ICAP rate of $8.75 per kW-month. On March 16, 2001, National Grid and others filed a motion to stay the FERC Order with the United States Court of Appeals for the First Circuit (First Circuit). The First Circuit stayed the ICAP rate of $8.75 per kW-month on March 30, 2001. On June 4, 2001, ISO New England made a filing to comply with the March FERC order that proposed a maximum charge of $4.87 per kW-month. On June 8, 2001, the First Circuit, ruling on the merits of the appeal to the FERC's orders imposing the $8.75 per kW-month charge, remanded the case to the FERC for further consideration. The First Circuit order allows the FERC to reinstate its initial order on a prospective basis, but asks the FERC to answer several questions to support its order. National Grid and others have asked the FERC to consider the June 4th ISO filing while it is reconsidering its initial order on remand. At this time, the Company cannot predict how ICAP charges will affect its forward looking power supply costs.

National Grid USA presented to the FERC in January 2001 a joint proposal, with ISO New England and other utilities in New England, for a Regional Transmission Organization (RTO) in the northeastern US. The RTO would consist of an ISO with responsibility for administering a competitive wholesale market in electricity and an Independent Transmission Company offering transmission services and undertaking transmission network development and the provision of connections for new generation. The proposal responds to the FERC's objective set out in "Order 2000," of separating transmission operations from market participation and would give the Independent Transmission Company, of which National Grid USA would be a member, the opportunity to propose financial incentives to deliver greater value for customers and shareholders. The proposal is subject to FERC approval and the ability of the utility group to reach agreement on a number of additional issues.

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 or liabilities, 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.

The Company has 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 March 31, 2001, this amounted to approximately $1.7 billion, including $1.1 billion related to the above-market costs of purchased power contracts, $0.2 billion related to accrued Yankee nuclear plant costs, and $0.4 billion related to other net CTC regulatory assets.

New England Power Company

Overview of Financial Results

Net income for the twelve months ended March 31, 2001 decreased $13 million compared with the twelve months ended December 31, 1999. The decrease is primarily due to goodwill amortization from the mergers with National Grid and EUA, increased purchased power costs, increased interest expense, and decreased mitigation incentives, partially offset by increased income due to the May 1, 2000 merger with Montaup, and increased earnings from nuclear operations.

Net income for the three months ended March 31, 2000 decreased $6 million compared with the same period in 1999 primarily due to the elimination of certain liabilities related to open access transmission tariffs of approximately $5 million in the first quarter of 1999.

Net income for the year ended December 31, 1999 decreased $52 million compared with the same period in 1998 as a result of the continuing impacts of the divestiture and the restructuring of the utility business. Partially offsetting the decrease was 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.

Operating Revenue

Operating revenue for the twelve months ended March 31, 2001 increased approximately $60 million compared with the twelve months ended December 31, 1999. The increase is due to increased sales and rates related to obligations to new customer load in Rhode Island, and increased unit contract sales from partially owned nuclear units that experienced refueling outages in 1999. These increases are also affected by the merger with Montaup, effective May 1, 2000. Partially offsetting these increases are decreased CTC revenues due to fully reconciling true-up mechanisms that allow the Company to adjust revenues proportionately with correlating expenses, and decreased transmission revenues. The transmission charge is a formula rate that recovers the Company's actual costs plus a return on actual investment.

Operating revenue for the three months ended March 31, 2000 decreased $33 million compared with the same period in 1999, largely due to CTC revenue of approximately $21 million from The Narragansett Electric Company (Narragansett Electric) in 1999 related to its access charge overcollections. This payment reduced Narragansett Electric's future CTC obligations. This additional revenue in 1999 had a corresponding impact to the amortization of CTC, discussed in "Operating Expenses" below. The decrease was also due to the elimination of certain liabilities related to open access transmission tariffs of $5 million in 1999. This decrease was partially offset by the impacts of increased standard offer rates effective January 1, 2000 and increased kWh sales in the three months ended March 31, 2000 compared with the same period in 1999.
Operating revenue for the year ended December 31, 1999 decreased $622 million compared with 1998 due to the divestiture and reduced CTC charges. Partially offsetting this decrease was an increase in transmission revenues associated with the elimination of certain liabilities related to open access transmission tariffs discussed above.

New England Power Company

Operating Expenses

Operating expenses for the twelve months ended March 31, 2001 increased approximately $51 million compared with the twelve months ended December 31, 1999.

Fuel for generation increased approximately $2 million primarily related to charges at the Wyman 4 generating plant. Purchased power expense for the twelve months ended March 31, 2001 increased approximately $62 million compared with the twelve months ended December 31, 1999. This increase is primarily attributed to the inclusion of Montaup's purchased power costs effective May 1, 2000, increased fuel prices, and an increase in standard offer purchases related to obligations to supply new customer load in Rhode Island, partially offset by decreased purchased power charges from the Yankee Nuclear Power Companies (Yankees). Charges from Maine Yankee decreased due to a refund for the termination of excess nuclear insurance coverage. Vermont Yankee purchased power charges decreased due to the effect of a refueling outage during the quarter ended December 31, 1999. In addition, purchased power charges from the Yankee Atomic nuclear power plant decreased as a result of the completion of the purchased power contract and final billing in June 2000.

Nuclear operation and maintenance expenses increased approximately $7 million primarily due to the merger of Montaup's ownership percentage of Millstone 3 with the Company's effective as of the merger date, as well as the effects of increased expenses related to refueling outages and other maintenance at Millstone 3 and Seabrook 1.

Other nonnuclear operation and maintenance expenses decreased approximately $5 million compared with the twelve months ended December 31, 1999 primarily due to reduced pension and postretirement healthcare expenses and reduced transmission costs. These decreases are partially offset by the receipt of a transmission wheeling refund that reduced expense in June 1999.

Depreciation and amortization expenses decreased approximately $24 million for the twelve months ended March 31, 2001 compared with the twelve months ended December 31, 1999. This decrease is primarily related to decreased CTC amortization as a result of the full recovery of the Company's CTC-related costs associated with its generating plants and regulatory assets (excluding Montaup's) at the end of 2000. This decrease is partially offset by the Company's payments to increase the Millstone 3 decommissioning trust fund to the level prescribed in the Release and Settlement Agreement with Northeast Utilities (NU) (see the "Millstone 3" disclosure in the "Nuclear units" section), as well as the effect of the addition of Montaup's ownership percentage of Millstone 3 effective as of the merger date.

Operating expenses for the three months ended March 31, 2000 decreased $27 million compared with the same period in 1999.

The increase in fuel and purchased power expense of approximately $5 million reflected increased purchased power expenses for standard offer requirements and increased kWh purchased.

Other operating expenses in the three months ended March 31, 2000 decreased approximately $3 million compared with the same period in 1999 due to the reimbursement of start-up costs from 1999 of the ISO New England in 2000. Maintenance expenses decreased approximately $1 million as a result of reduced expenses at the partially owned Millstone 3 and Seabrook 1 nuclear generating facilities.

Depreciation and amortization expenses in the three months ended March 31, 2000 decreased $23 million compared with the same period in 1999. This decrease was due to additional CTC amortization in 1999 related to the additional payment of approximately $21 million by Narragansett Electric to the Company, discussed above.

Operating expenses for the year ended December 31, 1999 decreased $543 million compared with 1998. The divestiture reduced all categories of operating expenses in 1999, with the exception of depreciation and amortization expense.

New England Power Company

The decrease in fuel expense and purchased power costs reflected 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 Yankees, 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 reflected 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 ISO 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 that experienced refueling outages in the second quarter of 1999.

Depreciation and amortization expenses increased $3 million for the year ended December 31, 1999 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 was also due to new transmission plant expenditures.

Other Income and Expense

Other income for the twelve months ended March 31, 2001 increased compared with the twelve months ended December 31, 1999 primarily due to increased earnings from the Yankees, partially offset by a decrease in allowance for equity funds used during construction.

The amortization of goodwill of approximately $18 million resulted from the mergers with National Grid and EUA.

Other income for the three months ended March 31, 2000 increased compared with the same period in 1999 as a result of decreased expenses related to employee incentive plans from workforce reductions following the divestiture, partially offset by merger related expenses in 2000.

For the year ended December 31, 1999, other income increased compared with the year ended December 31, 1998 primarily due 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.

Interest Expense

Interest expense increased for the twelve months ended March 31, 2001 compared with the twelve months ended December 31, 1999, primarily due to higher interest rates on variable rate long-term debt and increased short-term debt borrowings, as well as interest related to Montaup's CTC settlement.

Interest expense for the three months ended March 31, 2000 increased compared with the same period in 1999 primarily due to increased interest rates on variable rate long-term debt and interest on short-term debt borrowings not present in 1999.

Interest expense for the year ended December 31, 1999 decreased compared with the year ended December 31, 1998 principally due to reduced long-term and short-term debt as a result of the divestiture.

New England Power Company

Nuclear Units

Nuclear Units Permanently Shut Down

Three of the Yankees 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 as of 3/31/01 %	$(millions)	Date Retired	Future Estimated Billings to the Company $(millions)
Yankee Atomic	34.5	2	Feb 1992	0
Connecticut Yankee	19.5	15	Dec 1996	50
Maine Yankee	24.0	17	Aug 1997	129

In the case of each of these units, the Company has recorded a liability and a 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 and Connecticut Yankee recover their costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999 and July 2000, respectively. Prospectively, under the FERC settlement agreement, Connecticut Yankee agreed to reduce annual collections for decommissioning through the use of its pre-1983 spent fuel trust funds and to limit its ROE to 6 percent. In addition, Connecticut Yankee, Yankee Atomic, and Maine Yankee continue to pursue litigation against the Department of Energy (DOE) to assume financial responsibility for storage of spent nuclear fuel. Under rate provisions approved by the FERC for Connecticut Yankee and Yankee Atomic, any recovery from the DOE proceedings after litigation expenses and taxes will be returned to customers.

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.

Maine Yankee had hired Stone & Webster, Inc. (S&W), an engineering, construction, and consulting company, as the principal contractor to decommission the unit. In May 2000, Maine Yankee terminated its long-term contract with S&W and negotiated an arrangement with S&W to continue work through June 2000. In June 2000, S&W filed for Chapter 11 bankruptcy protection. Subsequently, Maine Yankee decided to self-manage the unit's decommissioning process. In June 2000, Federal Insurance Company (Federal) filed a complaint in S&W's bankruptcy proceeding which alleges that Maine Yankee improperly terminated its contract with S&W. If the court were to make such a finding, Federal would be excused from a $37 million performance bond liability to Maine Yankee. Federal's complaint has been removed to the US Federal District Court in Maine for jury trial. In August 2000, Maine Yankee filed a $78.2 million (later increased to $86 million) damage claim against S&W in the bankruptcy proceeding. At this time, the Company is unable to determine the potential impact, if any, of these developments.

Under the provisions of the Company's industry restructuring settlement agreements approved by state and federal regulators in 1998, 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 currently has minority interests in two operating nuclear generating units that the Company is engaged in efforts to divest: Vermont Yankee and Seabrook 1. In addition, the Company sold its 16.2 percent interest in Millstone 3 to Dominion Resources, Inc. (Dominion) on March 31, 2001. Until such time as the Company divests its operating nuclear interests, 80 percent of the revenues and operating costs related to the units will be allocated to customers through the CTC, with shareholders being allocated the balance.

Vermont Yankee

The following table summarizes the Company's interest in the Vermont Yankee Nuclear Power Corporation as of March 31, 2001:

	The Company's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 2000$)	Decommissioning Fund Balance	License Expiration
22.5	$12	$36	$102	$57	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. Several other parties, including Entergy Corporation (Entergy), indicated to the Vermont Public Service Board (VPSB) that they were prepared to make an offer for Vermont Yankee.

On February 14, 2001, the VPSB rejected Vermont Yankee's sale agreement with AmerGen and formally terminated the AmerGen proceeding on March 15, 2001. The VPSB also required Entergy to post a $26 million bond payable in the event that Entergy withdraws its offer. In addition, the VPSB stated that if the Entergy bond were redeemed, the proceeds would go exclusively to Vermont customers. The Vermont Yankee Board of Directors is presently considering its options with respect to that part of the order.

On March 15, 2001, Vermont Yankee terminated its agreement with AmerGen. After considering the pros and cons of shutting the plant down, continuing to operate it, or sell it, Vermont Yankee decided to proceed with a formal auction of the plant. The auction was officially launched on April 16, 2001. The Company expects that the winning bidder of the plant will be named in the fall of 2001. Any sale of the plant is contingent upon the receipt of regulatory approvals by the Securities and Exchange Commission, under the Public Utility Holding Company Act of 1935, the FERC, the Nuclear Regulatory Commission, the VPSB, and other state regulatory commissions with jurisdiction over other equity owners of Vermont Yankee.

Under the terms of the original AmerGen agreement, the existing power purchasers (including the Company) were required 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 would be recovered through the Company's CTC. At that time, the Company recorded a 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. With Vermont Yankee's termination of the agreement with AmerGen in March 2001, the Company was relieved of this obligation and accordingly reversed the liability and offsetting regulatory asset of $80 million. To date, the Company has not determined if it will enter into a purchased power agreement with a proposed new owner of Vermont Yankee.

New England Power Company

Seabrook 1

As part of its restructuring settlement with the State of New Hampshire, Public Service Company of New Hampshire (PSNH), through its affiliate, North Atlantic Energy Corporation (NAEC), committed to seek New Hampshire Public Utilities Commission (NHPUC) approval of a definitive plan to sell, via public auction administered by the NHPUC, its share of Seabrook 1, with such sale to occur no later than December 31, 2003. NAEC owns the largest percentage of the plant with a 35.98 percent interest, and its affiliate, North Atlantic Energy Service Corporation, is the plant operator. As part of its settlement, PSNH has also agreed to make all reasonable efforts to bundle its interests with those of other owners (including the Company) seeking to sell their interests so that a controlling interest may be offered in the auction.

In December 2000, NU filed its divestiture plan before the NHPUC, requesting an expeditious process in order to permit a prompt sale of the plant. Under the terms of the PSNH Settlement and enabling legislation, the NHPUC will administer the sale of the plant with the assistance of an asset sale specialist.

On April 12, 2001, the Company filed a Seabrook Divestiture Plan with the NHPUC as directed by its 1998 restructuring settlement agreement. Under the Divestiture Plan, the Company has indicated its interest in selling its share of Seabrook 1 and has requested that the NHPUC administer an auction on the Company's behalf under certain guidelines and conditions.

On May 22, 2001, legislation was enacted in New Hampshire to provide New Hampshire residents additional protections against the restructuring problems encountered in California. Although the legislation includes provisions to delay the sale of PSNH fossil and hydro generation assets, it directs the NHPUC to expedite the auction of the Seabrook Station in a manner that benefits customers of all New Hampshire utilities, including the Company.

Millstone 3

In November 1999, the Company entered into an agreement with NU and certain of NU's subsidiaries to settle claims made by the Company relative to the operation of Millstone 3. Among other things, the settlement provided for NU to include the Company's share of Millstone 3 in an auction of NU's share of the unit. Upon the closing of the sale, NU would pay the Company a total of $25 million, regardless of the actual sale price, with adjustments for certain capital and fuel procurement expenditures. The settlement also required NU to indemnify the Company and assume any residual liabilities resulting from the sale, including any requirements that the sellers continue to purchase output from the unit.

In August 2000, Dominion agreed to purchase the Millstone units, including the Company's 16.2 percent interest in Millstone 3, for $1.3 billion in cash.

In November 2000, the Rhode Island Attorney General and the Rhode Island Division of Public Utilities and Carriers filed a protest at the FERC contending that the payment the Company would receive from the sale of Millstone 3, as established by its agreement with NU, was insufficient. In December 2000, the Company and other parties to the Millstone sale submitted answers opposing Rhode Island's position and arguing, among other things, that Rhode Island's contention was well beyond the scope of the FERC proceeding. The Company further stated that concerns over the customer rate impact of the Company's agreement with NU would be more appropriately addressed under the terms of its restructuring settlements. On January 25, 2001, the FERC found that Rhode Island's objection was beyond the scope of the proceeding and approved the sale.

On March 31, 2001, the Company completed the sale of its 16.2 percent interest in Millstone 3 for approximately $27.9 million. In addition, the Company paid approximately $5.8 million to increase the decommissioning trust fund to the level prescribed in its settlement agreement with NU. The amounts received pursuant to the sale will, after reimbursement of the Company's transaction costs and net investment in Millstone 3, be credited to customers. The Company cannot predict whether the Rhode Island regulators will reassert their claims in connection with the recovery of stranded costs or the financial consequences if they do reassert their claims.

New England Power Company

As a result of the sale, certain balance sheet accounts related to the Company's investment in Millstone 3 were adjusted at March 31, 2001. Listed below are the significant adjustments recorded.

	Increase (Decrease) (In thousands)
Utility plant	$(679,345)
Construction work in process	$ (6,684)
Nuclear fuel	$ (10,974)
Materials and supplies	$ (6,107)
Decommissioning	$ (34,141)
Accumulated provisions for depreciation	$ 597,851
Regulatory assets - net book value and transaction costs	$ 94,501

NSTAR Settlement

On March 30, 2001, the Company reached a settlement in principal with NSTAR, formerly known as Boston Edison Company (BECO), resolving issues surrounding a $3 million refund to Montaup ordered by the FERC in January 2000. The order stemmed from an earlier proceeding initiated by the FERC where it required BECO to reduce its ROE under a life of unit purchased power agreement (PPA) with Montaup for 11 percent of the output from the Pilgrim plant. BECO subsequently divested its ownership in the Pilgrim plant in July 1999, and Montaup terminated its life of unit PPA in favor of a PPA that expires in 2004. BECO appealed the FERC Order to the First Circuit which, in turn, has remanded the case to the FERC for further proceedings. Proceeds from the refund have already been credited to customers through Montaup's CTC reconciliation mechanism. Under the terms of the settlement, the Company will return to BECO 75 percent of the refund amount, plus interest through March 31, 2001. The settlement is conditioned on consent from the parties to Montaup's restructuring settlement to recover this amount from customers through the CTC.

Wyman 4 Settlement

On April 23, 2001, Central Maine Power (CMP) and the Wyman 4 minority owners reached a settlement under which CMP will pay a total of $12 million to the minority owners. The Company's pro rata share of the settlement proceeds will be $2.9 million. The proceeds of the settlement, less legal costs, will be returned to customers via the CTC. The settlement is the result of arbitration brought by the Company and others against CMP regarding the sharing of CMP's proceeds from its sale of the Wyman 4 unit and site in Yarmouth, Maine in 1999. The Company is a 9 percent minority owner of the Wyman 4 generating unit.

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 March 31, 2001, the Company's tax exempt variable rate long-term debt had a carrying value and fair value of approximately $410 million. While the ultimate maturity dates of the underlying loan agreements range from 2015 through 2022, this debt is issued in tax exempt commercial paper mode. The various components that comprise this debt are issued for periods ranging from one day to 270 days, and are remarketed through remarketing agents at the conclusion of each period. The weighted average variable interest rate for the year ended March 31, 2001, was approximately 3.4 percent.

As discussed in the "Regulatory Environment" section, the Company remains obligated to provide transition power supply service to new customer load in Rhode Island at the standard offer price, but does not have a regulatory agreement that allows full recovery of the costs of such standard offer power. The Company meets this obligation through a combination of generation from some of its remaining generation sources, as well as by periodically procuring power at market prices. Over time, the Company cannot predict whether the resulting revenues will be sufficient to cover the costs of procuring such power. For the year ended March 31, 2001, the Company's losses from this obligation were approximately $5 million.

New England Power Company

Utility Plant Expenditures and Financing

Cash expenditures for the Company for utility plant totaled $57 million for the twelve months ended March 31, 2001 and were primarily transmission-related. The funds necessary for utility plant expenditures during the period were primarily provided by internal funds. Cash expenditures for fiscal year 2002 are estimated to be approximately $45 million, principally related to transmission functions. Internally generated funds are expected to fully cover capital expenditures in fiscal year 2002.

In September 2000, the Company repurchased 961 shares of its 6 percent $100 par value preferred stock for $79,766. Approximately $17,000 of this transaction was credited to retained earnings. In October 2000, the Company repurchased 350 shares of its 6 percent $100 par value preferred stock for $30,455. Approximately $4,000 of this transaction was credited to retained earnings.

In February 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.

Dividends payable at March 31, 2000, in the amount of $256 million were paid on June 27, 2000.

The Company has regulatory approval to issue up to $375 million of short-term debt. In October 2000, the Company received the necessary regulatory approvals to allow approximately $39 million of variable rate debt to remain outstanding through 2015. This results in classifying that debt as long-term rather than short-term.

At March 31, 2001, the Company had lines of credit and standby bond purchase facilities with banks totaling $456 million which are available to provide liquidity support for $410 million of the Company's long-term bonds in tax-exempt commercial paper mode, and for other corporate purposes. There were no borrowings under these lines of credit at March 31, 2001.

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 all these states (except Connecticut), 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. The Company's transmission facilities are part of National Grid USA's transmission operations, which are represented under the name National Grid Transmission USA. In addition, the Company also owns a minority interest in one joint owned nuclear generating unit and one fossil fuel generating unit, as well as minority equity interests in four nuclear generating companies, three of which own generating facilities that are permanently shut down. The output from these generating facilities is sold to third parties and used to serve the Company's load obligation.

2. System of Accounts and Financial Statement Presentation:

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

National Grid USA and its subsidiaries changed their fiscal year from a calendar year ending December 31 to a fiscal year ending March 31. National Grid USA and its subsidiaries made this change in order to align their fiscal years with that of National Grid Group plc (National Grid) (see Note B). The Company's first new full fiscal year began on April 1, 2000 and ended on March 31, 2001. The accompanying financial information as of March 31, 2001 and 2000, and for the twelve months ended March 31, 2001, reflects the new basis of accounting established for the Company's assets and liabilities in connection with the acquisition of National Grid USA by National Grid on March 22, 2000. The audited results of operations for the three month period ended March 31, 2000 includes an immaterial amount of goodwill amortization for the ten day period from March 22 to March 31, 2000. Due to the immateriality of this effect, this transitional period has not been separated into the period preceding and the period following the pushdown of goodwill.

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 2001 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 3.2 percent for the year ended March 31, 2001, 3.7 percent for the three month period ended March 31, 2000, 8.1 percent for the three month period ended March 31, 1999, and 7.6 percent and 6.1 percent for the years ended December 31, 1999 and 1998, respectively.

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4. Depreciation and Amortization:

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

(In thousands)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Depreciation - transmission related	**$15,055**	$ 3,269	$ 3,440	$ 13,222	$12,553
Depreciation - all other	**5,477**	(15)	354	1,286	46,256
Nuclear decommissioning costs (Note D-2)	**9,901**	923	699	3,637	2,719
Amortization:					
Millstone 3 additional amortization, pursuant to 1995 rate settlement	**-**	-	-	-	22,040
Regulatory assets covered by contract termination charges (Note C)	**48,329**	12,785	35,874	84,935	16,356
Total depreciation and amortization expense	**$78,762**	$16,962	$40,367	$103,080	$99,924

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 for all periods presented. Amortization of Millstone 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 at purchase date of 90 days or less as cash.

6. Property, Plant, and Equipment:

The Company's integrated system of transmission property consists of approximately 2,800 circuit miles of transmission lines and 116 substations.

7. Income Taxes:

Income taxes have been computed utilizing the asset and liability approach that requires the recognition of deferred tax assets and liabilities for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities (see Note F).

8. New Accounting Standards:

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). FAS 133 requires that an entity recognize all derivative instruments as either assets or liabilities in the statement of financial position and the measure of those instruments at fair value. In June 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date," which amends FAS 133 to be effective for all fiscal quarters of fiscal years beginning after June 15, 2000. FAS 133 was subsequently amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." The Company expects the adoption of the new standard during fiscal 2002 will not have a material impact on its financial position or results of operations.

In September 1999, the FASB issued an exposure draft of a proposed SFAS titled "Business Combinations and Intangible Assets - Accounting for Goodwill." A limited revision of the draft was issued on February 14, 2001. The proposed SFAS would continue recognition of goodwill as an asset but would not permit amortization as currently required by Accounting Principles Board Opinion No. 17, "Intangible Assets." In addition, goodwill would be tested periodically for impairment when events and circumstances occur indicating that it might be impaired. The proposed SFAS would be effective for fiscal years beginning after December 15, 2001. Early adoption would be permitted for companies with a fiscal year beginning after March 15, 2001. Currently, the Company is unable to determine the potential impact of the proposed accounting standard on its financial position or results of operations.

Note B - Mergers and Acquisitions

Merger with National Grid

On March 22, 2000, the merger of NEES and National Grid was completed, with NEES (renamed National Grid USA) becoming a wholly owned subsidiary of National Grid. The Company maintained its existing name and remained a wholly owned subsidiary of National Grid USA. The merger was accounted for by the purchase method, the application of which, including the recognition of goodwill, was pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $1.7 billion, of which the Company was allocated approximately $348 million. This amount was determined pursuant to a study conducted by an independent third party and is being amortized over 20 years. Amortization expense is approximately $17.4 million annually.

The purchase accounting method requires the revaluation of assets and liabilities to their fair value. This revaluation resulted in an adjustment to the Company's pension and postretirement benefit accounts in the amount of approximately $61 million, with an offsetting net credit to a regulatory liability account (see Note E).

Acquisition of EUA

The acquisition of Eastern Utilities Associates (EUA) by National Grid USA was completed on April 19, 2000 for $642 million. On May 1, 2000, Montaup Electric Company (Montaup), formerly a subsidiary of EUA, was merged into the Company.

The acquisition of EUA was accounted for by the purchase method, the application of which, including the recognition of goodwill, has been pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill recognized in this transaction was approximately $402 million, of which the Company was allocated approximately $8 million. This amount was determined pursuant to a study conducted by an independent third party and is being amortized over 20 years. Amortization expense is approximately $0.4 million annually.

The purchase accounting method requires the revaluation of assets and liabilities to their fair value. This revaluation resulted in an adjustment to the Company's pension and postretirement benefit accounts in the amount of approximately $3 million, with an offsetting net credit to a regulatory liability account (see Note E).

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As a result of the acquisition, Montaup's balance sheet accounts were incorporated into the financial statements of the Company as of May 1, 2000. Listed below are the significant account balances incorporated.

	May 1, 2000 balance (In thousands)
Assets	
Utility plant, at original cost	$227,114
Accumulated provisions for depreciation and amortization	$ (92,093)
Regulatory assets (current and long-term)	$547,412
Liabilities	
Other paid-in capital	$135,444
Deferred federal and state income taxes	$104,860
Accrued Yankee nuclear plant costs	$ 46,030
Purchased power obligations (current and long-term)	$176,257
Other reserves and deferred credits	$174,942

The accompanying statements of operations do not include any revenues or expenses related to Montaup prior to the companies' merger on May 1, 2000.

Note C - Regulatory Environment and Accounting Implications

Under 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 with which it has settlement agreements through CTCs. The Company's retail distribution affiliates recover CTC-related costs through delivery charges to distribution customers. The recovery of the Company's stranded costs (including the Montaup share) is divided into several categories. The Company's unrecovered costs associated with generating plants (nuclear and nonnuclear) and most regulatory assets were fully recovered through the CTC by the end of 2000 and earned a return on equity (ROE) averaging 9.7 percent. The Montaup share of unrecovered costs associated with generating plants and most regulatory assets will be fully recovered through the CTC by the end of 2009. 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 ROE. Until such time as the Company divests its operating nuclear interests, 80 percent of the revenues and operating costs related to the units will be allocated to customers through the CTC, with shareholders being allocated the balance.

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. Similar to the Company, Montaup also transferred its purchased power obligations as part of the divestiture and in return agreed to make fixed monthly payments. The aggregate fixed monthly payments, including the Montaup share, average $11.3 million per month through December 2009 toward the above-market cost of those contracts. The liability relating to purchased power obligations, which is also reflected in regulatory assets, represents the net present value of these fixed monthly payments. At March 31, 2001, the net present value was approximately $786 million. 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 $453 million), which were separate from the $786 million figure referred to above.

New England Power Company

Prior to divesting substantially all of its nonnuclear generation business in 1998, the Company was the wholesale supplier of the electric energy requirements to its retail distribution affiliates as well as unaffiliated customers. The Company's all-requirements contracts with its affiliated distribution companies, as well as with some unaffiliated customers, were generally terminated pursuant to settlement agreements and tariff provisions in 1998. However, the Company remains obligated to provide transition power supply service to new customer load in Rhode Island at the standard offer price, but does not have a regulatory agreement that necessarily allows full recovery of the costs of such standard offer power. Consequently, the Company is at risk for the difference between the actual cost of serving this load and the revenue received from this obligation. The standard offer rate that the Company charges for continuing to meet this obligation increased from 3.5 cents per kilowatthour (kWh) in 1999 to 3.8 cents per kWh effective January 1, 2000. The standard offer rate is also subject to a rolling twelve-month fuel index adjustment factor, which increased the rate by an additional 0.121 cents per kWh beginning in April 2000 up to 2.404 cents per kWh by March 2001. The Company meets this obligation through a combination of generation from some of its remaining generation sources, as well as by periodically procuring power at market prices. Over time, the Company cannot predict whether the resulting revenues will be sufficient to cover the costs of procuring such power. For the year ended March 31, 2001, the Company's losses from this obligation were approximately $5 million.

In a December 15, 2000 Order, the FERC rejected the Independent System Operator's (ISO New England) proposed $0.17 per kW-month Installed Capacity (ICAP) deficiency charge and reinstated an administratively-determined deficiency charge of $8.75 per kW-month, retroactive to August 1, 2000. Several parties, including the Company, filed motions requesting rehearing and stay of the FERC's order. On January 10, 2001, the FERC granted these motions. On March 6, 2001, the FERC reversed its earlier order by allowing ISO New England's previously proposed ICAP rate of $0.17 per kW-month to be effective from August 1, 2000 through March 31, 2001. Effective April 1, 2001, the FERC ordered an ICAP rate of $8.75 per kW-month. On March 16, 2001, National Grid and others filed a motion to stay the FERC Order with the United States Court of Appeals for the First Circuit (First Circuit). The First Circuit stayed the ICAP rate of $8.75 per kW-month on March 30, 2001. On June 4, 2001, ISO New England made a filing to comply with the March FERC order that proposed a maximum charge of $4.87 per kW-month. On June 8, 2001, the First Circuit, ruling on the merits of the appeal to the FERC's orders imposing the $8.75 per kW-month charge, remanded the case to the FERC for further consideration. The First Circuit order allows the FERC to reinstate its initial order on a prospective basis, but asks the FERC to answer several questions to support its order. National Grid and others have asked the FERC to consider the June 4th ISO filing while it is reconsidering its initial order on remand. At this time, the Company cannot predict how ICAP charges will affect its forward looking power supply costs.

National Grid USA presented to the FERC in January 2001 a joint proposal, with ISO New England and other utilities in New England, for a Regional Transmission Organization (RTO) in the northeastern US. The RTO would consist of an ISO with responsibility for administering a competitive wholesale market in electricity and an Independent Transmission Company offering transmission services and undertaking transmission network development and the provision of connections for new generation. The proposal responds to the FERC's objective set out in "Order 2000", of separating transmission operations from market participation and would give the Independent Transmission Company, of which National Grid USA would be a member, the opportunity to propose financial incentives to deliver greater value for customers and shareholders. The proposal is subject to FERC approval and the ability of the utility group to reach agreement on a number of additional issues.

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 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (FAS 71), which requires regulated entities, in appropriate circumstances, to establish regulatory assets or liabilities, 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 FASB 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.

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The Company has 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 March 31, 2001, this amounted to approximately $1.7 billion, including $1.1 billion related to the above-market costs of purchased power contracts, $0.2 billion related to accrued Yankee nuclear plant costs, and $0.4 billion related to other net CTC regulatory assets.

Note D - Commitments and Contingencies

1. Yankee Nuclear Power Companies

The Company has minority interests in four Yankee Nuclear Power Companies (Yankees). 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)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Operating revenue	**$ 291,628**	$ 81,225	$ 89,244	$ 377,039	$ 439,046
Net income	**$ 29,589**	$ 5,310	$ 5,138	$ 13,890	$ 23,218
Company's equity in net income	**$ 6,703**	$ 862	$ 515	$ 2,939	$ 5,284
Net plant	**160,701**	167,317	166,062	172,100	171,582
Other assets	**1,893,733**	2,520,887	2,798,948	2,631,750	2,810,613
Liabilities and debt	**(1,855,775)**	(2,437,609)	(2,707,749)	(2,554,261)	(2,723,454)
Net assets	**$ 198,659**	$ 250,595	$ 257,261	$ 249,589	$ 258,741
Company's equity in net assets	**$ 46,474**	$ 45,966	$ 47,323	$ 46,233	$ 48,538
Company's purchased electric energy:					
Vermont Yankee	**$ 31,899**	$ 7,761	$ 7,874	$ 37,551	$ 35,108
All other Yankees	**$ 21,616**	$ 9,324	$ 9,370	$ 37,765	$ 48,543

At March 31, 2001, approximately $7 million of undistributed earnings of the nuclear power companies were included in the Company's retained earnings.

New England Power Company

2. Nuclear Units

Nuclear Units Permanently Shut Down

Three of the Yankees 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 as of 3/31/01 %	$(millions)	Date Retired	Future Estimated Billings to the Company $(millions)
Yankee Atomic	34.5	2	Feb 1992	0
Connecticut Yankee	19.5	15	Dec 1996	50
Maine Yankee	24.0	17	Aug 1997	129

In the case of each of these units, the Company has recorded a liability and a 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 and Connecticut Yankee recover their costs, including a return, in accordance with settlement agreements approved by the FERC in May 1999 and July 2000, respectively. Prospectively, under the FERC settlement agreement, Connecticut Yankee agreed to reduce annual collections for decommissioning through the use of its pre-1983 spent fuel trust funds and to limit its ROE to 6 percent. In addition, Connecticut Yankee, Yankee Atomic, and Maine Yankee continue to pursue litigation against the Department of Energy (DOE) to assume financial responsibility for storage of spent nuclear fuel. Under rate provisions approved by the FERC for Connecticut Yankee and Yankee Atomic, any recovery from the DOE proceedings after litigation expenses and taxes will be returned to customers.

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.

Maine Yankee had hired Stone & Webster, Inc. (S&W), an engineering, construction, and consulting company, as the principal contractor to decommission the unit. In May 2000, Maine Yankee terminated its long-term contract with S&W and negotiated an arrangement with S&W to continue work through June 2000. In June 2000, S&W filed for Chapter 11 bankruptcy protection. Subsequently, Maine Yankee decided to self-manage the unit's decommissioning process. In June 2000, Federal Insurance Company (Federal) filed a complaint in S&W's bankruptcy proceeding which alleges that Maine Yankee improperly terminated its contract with S&W. If the court were to make such a finding, Federal would be excused from a $37 million performance bond liability to Maine Yankee. Federal's complaint has been removed to the US Federal District Court in Maine for jury trial. In August 2000, Maine Yankee filed a $78.2 million (later increased to $86 million) damage claim against S&W in the bankruptcy proceeding. At this time, the Company is unable to determine the potential impact, if any, of these developments.

Under the provisions of the Company's industry restructuring settlement agreements approved by state and federal regulators in 1998, the Company recovers all costs, including shutdown costs, that the FERC allows these Yankee companies to bill to the Company.

New England Power Company

Operating Nuclear Units

The Company currently has minority interests in two operating nuclear generating units that the Company is engaged in efforts to divest: Vermont Yankee and Seabrook 1. In addition, the Company sold its 16.2 percent interest in Millstone 3 to Dominion Resources, Inc. (Dominion) on March 31, 2001. Until such time as the Company divests its operating nuclear interests, 80 percent of the revenues and operating costs related to the units will be allocated to customers through the CTC, with shareholders being allocated the balance.

Vermont Yankee

The following table summarizes the Company's interest in the Vermont Yankee Nuclear Power Corporation as of March 31, 2001:

	The Company's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 2000 $)	Decommissioning Fund Balance	License Expiration
22.5	$12	$36	$102	$57	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. Several other parties, Including Entergy Corporation (Entergy), indicated to the Vermont Public Service Board (VPSB) that they were prepared to make an offer for Vermont Yankee.

On February 14, 2001, the VPSB rejected Vermont Yankee's sale agreement with AmerGen and formally terminated the AmerGen proceeding on March 15, 2001. The VPSB also required Entergy to post a $26 million bond payable in the event that Entergy withdraws its offer. In addition, the VPSB stated that if the Entergy bond were redeemed, the proceeds would go exclusively to Vermont customers. The Vermont Yankee Board of Directors is presently considering its options with respect to that part of the order.

On March 15, 2001, Vermont Yankee terminated its agreement with AmerGen. After considering the pros and cons of shutting the plant down, continuing to operate it, or sell it, Vermont Yankee decided to proceed with a formal auction of the plant. The auction was officially launched on April 16, 2001. The Company expects that the winning bidder of the plant will be named in the fall of 2001. Any sale of the plant is contingent upon the receipt of regulatory approvals by the SEC, under the 1935 Act, the FERC, the NRC, the VPSB, and other state regulatory commissions with jurisdiction over other equity owners of Vermont Yankee.

Under the terms of the original AmerGen agreement, the existing power purchasers (including the Company) were required 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 would be recovered through the Company's CTC. At that time, the Company recorded a 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. With Vermont Yankee's termination of the agreement with AmerGen in March 2001, the Company was relieved of this obligation and accordingly reversed the liability and offsetting regulatory asset of $80 million. To date, the Company has not determined if it will enter into a purchased power agreement with a proposed new owner of Vermont Yankee.

New England Power Company

Seabrook 1
The following table summarizes the Company's interest in the Seabrook 1 nuclear generating unit as of March 31, 2001:

	The Company's share of (millions of dollars)			
The Company's Ownership Interest (%)	Net Plant Assets	Estimated Decommissioning Cost (in 2000 $)	Decommissioning Fund Balances*	License Expiration
10	$17**	$61	$16	2026

*Certain additional amounts are anticipated to be available through tax deductions.
**Represents post-December 1995 spending including nuclear fuel.

As part of its restructuring settlement with the State of New Hampshire, Public Service Company of New Hampshire (PSNH), through its affiliate, North Atlantic Energy Corporation (NAEC), committed to seek New Hampshire Public Utilities Commission (NHPUC) approval of a definitive plan to sell, via public auction administered by the NHPUC, its share of Seabrook 1, with such sale to occur no later than December 31, 2003. NAEC owns the largest percentage of the plant with a 35.98 percent interest, and its affiliate, North Atlantic Energy Service Corporation, is the plant operator. As part of its settlement, PSNH has also agreed to make all reasonable efforts to bundle its interests with those of other owners (including the Company) seeking to sell their interests so that a controlling interest may be offered in the auction.

In December 2000, Northeast Utilities (NU) filed its divestiture plan before the NHPUC, requesting an expeditious process in order to permit a prompt sale of the plant. Under the terms of the PSNH Settlement and enabling legislation, the NHPUC will administer the sale of the plant with the assistance of an asset sale specialist.

On April 12, 2001, the Company filed a Seabrook Divestiture Plan with the NHPUC as directed by its 1998 restructuring settlement agreement. Under the Divestiture Plan, the Company has indicated its interest in selling its share of Seabrook 1 and has requested that the NHPUC administer an auction on the Company's behalf under certain guidelines and conditions.

On May 22, 2001, legislation was enacted in New Hampshire to provide New Hampshire residents additional protections against the restructuring problems encountered in California. Although the legislation includes provisions to delay the sale of PSNH fossil and hydro generation assets, it directs the NHPUC to expedite the auction of the Seabrook Station in a manner that benefits customers of all New Hampshire utilities, including the Company.

Millstone 3
In November 1999, the Company entered into an agreement with NU and certain of NU's subsidiaries to settle claims made by the Company relative to the operation of Millstone 3. Among other things, the settlement provided for NU to include the Company's share of Millstone 3 in an auction of NU's share of the unit. Upon the closing of the sale, NU would pay the Company a total of $25 million, regardless of the actual sale price, with adjustments for certain capital and fuel procurement expenditures. The settlement also required NU to indemnify the Company and assume any residual liabilities resulting from the sale, including any requirements that the sellers continue to purchase output from the unit.

In August 2000, Dominion agreed to purchase the Millstone units, including the Company's 16.2 percent interest in Millstone 3, for $1.3 billion in cash.

New England Power Company

In November 2000, the Rhode Island Attorney General and the Rhode Island Division of Public Utilities and Carriers filed a protest at the FERC contending that the payment the Company would receive from the sale of Millstone 3, as established by its agreement with NU, was insufficient. In December 2000, the Company and other parties to the Millstone sale submitted answers opposing Rhode Island's position and arguing, among other things, that Rhode Island's contention was well beyond the scope of the FERC proceeding. The Company further stated that concerns over the customer rate impact of the Company's agreement with NU would be more appropriately addressed under the terms of its restructuring settlements. On January 25, 2001, the FERC found that Rhode Island's objection was beyond the scope of the proceeding and approved the sale.

On March 31, 2001, the Company completed the sale of its 16.2 percent interest in Millstone 3 for approximately $27.9 million. In addition, the Company paid approximately $5.8 million to increase the decommissioning trust fund to the level prescribed in its settlement agreement with NU. The amounts received pursuant to the sale will, after reimbursement of the Company's transaction costs and net investment in Millstone 3, be credited to customers. The Company cannot predict whether the Rhode Island regulators will reassert their claims in connection with the recovery of stranded costs or the financial consequences if they do reassert their claims.

As a result of the sale, certain balance sheet accounts related to the Company's investment in Millstone 3 were adjusted at March 31, 2001. Listed below are the significant adjustments recorded.

	Increase (Decrease) (In thousands)
Utility plant	$(679,345)
Construction work in process	$ (6,684)
Nuclear fuel	$ (10,974)
Materials and supplies	$ (6,107)
Decommissioning	$ (34,141)
Accumulated provisions for depreciation	$ 597,851
Regulatory assets –net book value and transaction costs	$ 94,501

Nuclear Decommissioning

The Company is liable for its share of decommissioning costs for 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 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 Seabrook 1 through depreciation expense. In addition, the Company is paying its portion of projected decommissioning costs for Connecticut Yankee and Maine Yankee. The Company has completed its projected decommissioning obligation for Yankee Atomic. Such costs reflect estimates of total decommissioning costs approved by the FERC.

In New Hampshire, legislation was enacted in 1998 that 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, there is a single owner of an approximate 15 percent share of Seabrook 1 that is subject to the legislation. The impact of this legislation to the Company is not considered material to its financial position or results of operation.

The Company has been working to amend the current nuclear decommissioning statute to become effective upon the sale of Seabrook. Decommissioning legislation has passed in the New Hampshire legislature. This bill, initiated and supported by Seabrook's joint owners, including the Company and members of the New Hampshire Nuclear Decommissioning Financing Committee (NHNDFC), modifies New Hampshire's current decommissioning law and removes utility owners from the role of proportional guarantor for non-utility owners. The new legislation also seeks to protect customers from future decommissioning risks by requiring a buyer to provide funding assurance even in the event of a premature shutdown at the plant. The bill also enhances the potential sale price of Seabrook by allowing the buyer to retain any decommissioning funds in excess of those contributed by customers of the present utility owners and by reducing the standard set by the NHNDFC for non-radiological decommissioning.

The Nuclear Waste Policy Act of 1982 establishes that the federal government (through the 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 Seabrook 1 nuclear generating unit. Prior to 1998, the Company recovered this fee through its fuel clause. Under 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 filed claims for money damages in the U.S. Court of Federal Claims for the costs associated with the DOE's failure to begin to take fuel in 1998. As an interim measure until the DOE meets its contractual obligations to dispose of their spent fuel, those companies are proceeding with construction of independent spent fuel storage installations on the plant sites.

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. There is no assurance that decommissioning costs actually incurred by Seabrook 1 or the Yankees 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, the funds collected for decommissioning to that point may be insufficient. Under 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 and Seabrook 1 would subject the Company to a $28.6 million maximum assessment per incident. The Company's payment of any such assessment would be limited to a maximum of $3.2 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 $3.0 million with respect to the current policy period.

3. Plant Expenditures

The Company's utility plant expenditures are estimated to be approximately $45 million for fiscal year 2002. At March 31, 2001, 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. At March 31, 2001, the Company had guaranteed approximately $18 million of project debt with terms through 2015. The Company's rights and obligations under its support agreements were transferred to the purchaser of its nonnuclear generation. Also, as a result of the National Grid USA merger with EUA, at March 31, 2001, the Company had guaranteed an additional amount of approximately $4 million originally guaranteed by Montaup. The Company remains an obligor under the support agreements until 2020. Costs associated with these support agreements are recoverable through the CTCs.

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 March 2001, the charges assessed Norwood amount to approximately $29 million, all of which remain unpaid. The Company filed a collection action in Massachusetts Superior Court (Superior Court). The Superior Court deferred action until the various appeals described below were decided. On March 14, 2001, the Superior Court ordered Norwood to pay the Company $27 million including interest. Norwood was ordered to pay the judgement in monthly installments of $600,000. Norwood has also entered a consent order to establish a segregated account for the benefit of the Company in the amount of $14 million and to make regular additions to the account.

Separately, Norwood filed suit in Federal District Court (District Court) in April 1997 alleging that the divestiture of the Company's nonnuclear generating business (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 consolidated appeals Norwood made from the FERC's orders approving the Company's divestiture, the wholesale rate settlement between the Company and its distribution affiliates, and the CTC tariff amendment. In February 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 alleged generation market power. In February and March 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. In May 2000, Norwood petitioned the US Supreme Court for review of the First Circuit decisions. In October 2000, the US Supreme Court refused Norwood's petitions to review the First Circuit decisions affirming (a) the FERC's approval of the CTC, the divestiture, and the settlement agreements regarding termination of the Company's power sales agreements with its affiliates, and (b) the District Court's dismissal of Norwood's antitrust and breach of contract claims.

In the District Court action, in April 2000, the Company renewed its motion to dismiss Norwood's remaining claim. Norwood amended its complaint to reassert a request for rescission of the divestiture, which it had earlier dropped. A hearing took place before the District Court in July 2000.

Norwood has also appealed a June 1999 FERC decision that rejected Norwood's challenge to the calculation of the CTC based on the terms of the 1983 power contract, which Norwood contended ended in October 1998, not October 2008. In June 2000, the First Circuit rejected Norwood's appeal. Norwood filed a petition for certiorari to the US Supreme Court for review of the First Circuit's decision. On April 24, 2001, the US Supreme Court denied Norwood's petition.

7. Settlements

NSTAR Settlement
On March 30, 2001, the Company reached a settlement in principal with NSTAR, formerly known as Boston Edison Company (BECO), resolving issues surrounding a $3 million refund to Montaup ordered by the FERC in January 2000. The order stemmed from an earlier proceeding initiated by the FERC where it required BECO to reduce its ROE under a life of unit purchased power agreement (PPA) with Montaup for 11 percent of the output from the Pilgrim plant. BECO subsequently divested its ownership in the Pilgrim plant in July 1999, and Montaup terminated its life of unit PPA in favor of a PPA that expires in 2004. BECO appealed the FERC Order to the First Circuit which, in turn, has remanded the case to the FERC for further proceedings. Proceeds from the refund have already been credited to customers through Montaup's CTC reconciliation mechanism. Under the terms of the settlement, the Company will return to BECO 75 percent of the refund amount, plus interest through March 31, 2001. The settlement is conditioned on consent from the parties to Montaup's restructuring settlement to recover this amount from customers through the CTC.

Wyman 4 Settlement
On April 23, 2001, Central Maine Power (CMP) and the Wyman 4 minority owners reached a settlement under which CMP will pay a total of $12 million to the minority owners. The Company's pro rata share of the settlement proceeds will be $2.9 million. The proceeds of the settlement, less legal costs, will be returned to customers via the CTC. The settlement is the result of arbitration brought by the Company and others against CMP regarding the sharing of CMP's proceeds from its sale of the Wyman 4 unit and site in Yarmouth, Maine in 1999. The Company is a 9 percent minority owner of the Wyman 4 generating unit.

Note E - Employee Benefits

1. Pension Plan:
The Company participates with other subsidiaries of National Grid USA in a noncontributory, defined benefit plan covering substantially all employees of the Company. The plan provides 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 the year ended March 31, 2001, the three months ended March 31, 2000, and the years ended December 31, 1999 and 1998 included the following components:

(thousands of dollars)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Year Ended December 31, 1999	1998
Service cost - benefits earned during the period	**$ 482**	$ 118	$ 527	$ 2,430
Plus (less):				
Interest cost on projected benefit obligation	**8,381**	1,760	7,044	7,435
Return on plan assets at expected long-term rate	**(12,440)**	(2,200)	(8,090)	(8,675)
Amortization of transition obligation	**-**	(33)	(170)	(184)
Amortization of prior service cost	**-**	24	115	161
Amortization of net (gain)/loss	**-**	(100)	36	159
Curtailment (gain)/loss	**-**	-	-	(5,680)
Benefit cost/(income)	**$ (3,577)**	$ (431)	$ (538)	$ (4,354)
Special termination benefits not included above	**$ -**	$ -	$ -	$10,911

New England Power Company

The funded status of the plan cannot be presented separately for the Company as the Company participates in the plan with other National Grid USA subsidiaries.

The following provides a reconciliation of benefit obligations and plan assets for the National Grid USA companies' plan:

(In millions)	At March 31, 2001	At March 31, 2000	At December 31, 1999
Change in benefit obligation:			
Benefit obligation at beginning of period	**$ 800**	$ 789	$ 843
Service cost	**12**	2	11
Interest cost	**72**	15	56
Actuarial (gain)/loss	**47**	10	(55)
Benefits paid	**(90)**	(16)	(66)
Acquisitions	**188**	-	-
Special termination benefits	**6**	-	-
Plan amendments	**20**	-	-
Benefit obligation at end of period	**1,055**	800	789
Reconciliation of change in plan assets:			
Fair value of plan assets at beginning of period	**991**	947	837
Actual return on plan assets during year	**(59)**	59	117
Company contributions	**8**	1	59
Benefits paid from plan assets	**(90)**	(16)	(66)
Acquisitions	**232**	-	-
Fair value of plan assets at end of period	**1,082**	991	947
Funded status	**27**	191	158
Unrecognized actuarial (gain)/loss	**206**	-	(206)
Unrecognized prior service cost	**20**	-	5
Unrecognized transition (asset)/liability	**-**	-	(3)
Net amount recognized	**$ 253**	$ 191	$ (46)
Amounts recognized in the statement of financial position consist of:			
Prepaid benefit cost	**$ 338**	$ 262	$ 14
Accrued benefit liability	**(90)**	(71)	(66)
Intangible asset	**-**	-	2
Accumulated other comprehensive income	**5**	-	4
Net amount recognized	**$ 253**	$ 191	$ (46)

	March 31, 2001	March 31, 2000	December 31, 1999	December 31, 1998
Assumptions used to determine pension cost:				
Discount rate	7.50%	7.75%	7.75%	6.75%
Average rate of increase in future compensation level	4.61%	5.10%	5.10%	4.13%
Expected long-term rate of return on assets	8.75%	8.50%	8.50%	8.50%

Plan assets are composed primarily of equity and fixed income securities. Fair value adjustments of approximately $33 million are reflected in the Company's financial statements at March 31, 2000.

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 the year ended March 31, 2001, the three months ended March 31, 2000, and the years ended December 31, 1999 and 1998 included the following components:

(thousands of dollars)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Year Ended December 31, 1999	Year Ended December 31, 1998
Service cost - benefits earned during the period	**$ 210**	$ 47	$ 193	$ 1,109
Plus (less):				
Interest cost on projected benefit obligation	**3,337**	786	2,816	3,244
Return on plan assets at expected long-term rate	**(3,537)**	(803)	(2,896)	(2,656)
Amortization of transition obligation	**-**	19	85	1,732
Amortization of prior service cost	**-**	-	-	5
Amortization of net (gain)/loss	**-**	(285)	(1,252)	(1,138)
Curtailment (gain)/loss	**-**	-	-	27,149
Benefit cost/(income)	**$ 10**	$(236)	$(1,054)	$29,445
Special termination benefits not included above	**$ -**	$ -	$ -	$ 439

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The following provides a reconciliation of benefit obligations and plan assets including fair value adjustments recorded in March 2000 of approximately $28 million:

(millions of dollars)	At March 31, 2001	At March 31, 2000	At December 31, 1999
Change in benefit obligation:			
Benefit obligation at beginning of period	**$38**	$42	$ 41
Service cost	-	-	-
Interest cost	**3**	1	3
Actuarial (gain)/loss	**2**	(4)	-
Benefits paid	**(4)**	(1)	(2)
Acquisitions	**8**	-	-
Benefit obligation at end of period	**47**	38	42
Reconciliation of change in plan assets:			
Fair value of plan assets at beginning of period	**40**	39	36
Actual return on plan assets during year	**(1)**	2	4
Company contributions	**2**	-	1
Benefits paid from plan assets	**(4)**	(1)	(2)
Acquisitions	**4**	-	-
Fair value of plan assets at end of period	**41**	40	39
Funded status	**(6)**	2	(3)
Unrecognized actuarial (gain)/loss	**7**	-	(25)
Unrecognized prior service cost	**-**	-	-
Unrecognized transition (asset)/liability	**-**	-	1
Net amount recognized	**$ 1**	$ 2	$(27)

	March 31,		December 31,	
	2001	2000	1999	1998
Assumptions used to determine postretirement benefit cost:				
Discount rate	7.50%	7.75%	7.75%	6.75%
Expected long-term rate of return on assets	8.48%	8.40%	8.42%	8.35%
Health care cost rates:				
1998 to 1999				5.25%
2000	8.25%	8.25%	8.25%	5.25%
2001	8.00%	6.75%	6.75%	5.25%
2002	6.50%	5.25%	5.25%	5.25%
2003 and beyond	5.00%	5.25%	5.25%	5.25%

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 March 31, 2001 by approximately $5 million or decrease the APBO by approximately $5 million, and change the net periodic cost for fiscal year 2001 by approximately $400,000.

The Company generally funds the annual tax-deductible contributions.

In connection with the mergers referred to in Note B, the Company adjusted its pension and PBOP accounts in the amount of approximately $64 million, with an offsetting net credit to a regulatory liability account. This adjustment eliminated any unrecognized net gain or loss, unrecognized prior service cost, or unrecognized transition obligation of the Company. The regulatory liability is being amortized over the service period to pension and postretirement health care costs.

Note F - Income Taxes

The Company and other subsidiaries intend to elect to participate with National Grid General Partnership, National Grid USA's parent company that is wholly owned by National Grid, 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 1996.

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

(In thousands)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Income taxes charged to operations	**$44,946**	$9,641	$13,100	$37,633	$ 73,594
Income taxes charged (credited) to "Other income"	**(52)**	(4)	-	1,985	(19,582)
Total income taxes	**$44,894**	$9,637	$13,100	$39,618	$ 54,012

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

(In thousands)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Current income taxes	**$ 56,374**	$12,545	$ 7,374	$ 25,507	$ 280,734
Deferred income taxes	**(1,111)**	(581)	10,732	25,921	(204,129)
Investment tax credits, net	**(10,369)**	(2,327)	(5,006)	(11,810)	(22,593)
Total income taxes	**$ 44,894**	$ 9,637	$13,100	$ 39,618	$ 54,012

Since 1998, the Company has been amortizing previously deferred investment tax credits (ITC) related to generation investments over the CTC recovery period. Unamortized ITC related to generating units divested in 1998 and 2001 were credited to other income pursuant to federal tax law.

Previously recognized ITC related to transmission facilities are amortized over their estimated productive lives.

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

(In thousands)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Federal income taxes	**$ 38,350**	$8,035	$10,975	$ 33,746	$ 41,255
State income taxes	**6,544**	1,602	2,125	5,872	12,757
Total income taxes	**$ 44,894**	$ 9,637	$13,100	$ 39,618	$ 54,012

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:

(In thousands)	**Year Ended March 31, 2001**	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998
Computed tax at statutory rate	**$36,118**	$ 8,435	$11,706	$38,721	$ 61,917
Increases (reductions) in tax resulting from:					
Amortization of investment tax credits	**(7,762)**	(1,513)	(3,254)	(7,677)	(15,157)
State income taxes, net of federal income tax benefit	**4,254**	1,042	1,381	3,817	8,292
Rate recovery of deficiency in deferred tax reserves	**4,339**	1,617	3,508	8,207	-
Amortization of goodwill	**6,267**	-	-	-	-
Prior year tax adjustment	**773**	-	-	(2,028)	(188)
Millstone 3 sale	**1,787**	-	-	-	-
All other differences	**(882)**	56	(241)	(1,422)	(852)
Total income taxes	**$44,894**	$ 9,637	$13,100	$39,618	$ 54,012

New England Power Company

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

(In millions)	**At March 31, 2001**	At March 31, 2000	At December 31, 1999
Deferred tax asset:			
Plant related	**$ 67**	$ 67	$ 67
Investment tax credits	**4**	6	8
All other	**30**	3	2
	101	76	77
Deferred tax liability:			
Plant related	**(211)**	(159)	(157)
All other, principally regulatory assets	**(162)**	(93)	(100)
	(373)	(252)	(257)
Net deferred tax liability	**$(272)**	$(176)	$(180)

Note G - Short-term Borrowings and Other Accrued Expenses

At March 31, 2001, the Company had no short-term debt outstanding. The Company has regulatory approval to issue up to $375 million of short-term debt. In October 2000, the Company received the necessary regulatory approvals to allow approximately $39 million of variable rate debt to remain outstanding through 2015. This results in classifying that debt as long-term rather than short-term. Proceeds from the increase in short-term debt were utilized to pay Montaup's debt of approximately $91 million and purchased power contract obligations of approximately $60 million. 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 that 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 March 31, 2001, the Company had lines of credit and standby bond purchase facilities with banks totaling $456 million which are available to provide liquidity support for $410 million of the Company's long-term bonds in tax-exempt commercial paper mode, and for other corporate purposes. There were no borrowings under these lines of credit at March 31, 2001. Fees are paid on the lines and facilities in lieu of compensating balances.

The components of other accrued expenses are as follows:

(In thousands)	**At March 31, 2001**	At March 31, 2000	At December 31, 1999
Accrued wages and benefits	**$1,191**	$ 1,215	$ 1,063
Rate adjustment mechanisms	**5,555**	9,110	14,550
Other	**875**	554	80
	$7,621	$10,879	$15,693

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Note H - Cumulative Preferred Stock

A summary of cumulative preferred stock at March 31, 2001, March 31, 2000, and December 31, 1999 is as follows (in thousands of dollars except for share data):

	Shares Outstanding			Amount			Dividends Declared			Call Price
	2001	2000	1999	**2001**	2000	1999	**2001**	2000	1999	
$100 par value										
6.00% Series	**14,361**	15,672	15,672	**$1,436**	$1,567	$1,567	**$91**	$24	$94	(a)

(a) Noncallable.

The annual dividend requirement for cumulative preferred stock was approximately $86,000 for 2001 and 2000, and $94,000 for 1999. In 2000, the Company repurchased or redeemed preferred stock with a par value of approximately $131,000.

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:

(In thousands)

Series	Rate %	Maturity	**At March 31, 2001**	At March 31, 2000	At December 31, 1999
Pollution Control Revenue Bonds:					
CDA (a)	variable	October 15, 2015	**$ 38,500**	$ -	$ -
MIFA 1 (a)	variable	March 1, 2018	**79,250**	79,250	79,250
BFA 1 (b)	variable	November 1, 2020	**135,850**	135,850	135,850
BFA 2 (b)	variable	November 1, 2020	**50,600**	50,600	50,600
MIFA 2 (a)	variable	October 1, 2022	**106,150**	106,150	106,150
Unamortized discounts			**(71)**	(77)	(79)
Total long-term debt			**$410,279**	$371,773	$371,771

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

At March 31, 2001, interest rates on the Company's variable rate long-term bonds ranged from 3.0 percent to 4.2 percent.

At March 31, 2001, the Company's long-term debt had a carrying value and fair value of approximately $410,000,000. The fair value of debt that reprices frequently at market rates approximates carrying value.

New England Power Company

Note J - Common Stock

The purchase accounting method was used in the merger of National Grid and NEES, and in the acquisition of EUA by National Grid USA. This method resulted in a retained earnings adjustment of approximately $16 million for the National Grid/National Grid USA merger in order to reflect post-merger earnings. A retained earnings adjustment in the amount of approximately $0.5 million resulted from the merger of Montaup into the Company. Both mergers resulted in adjustments to other paid-in capital to reflect the pushdown of goodwill.

The Company repurchased shares of its common stock in 1999 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

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 the year ended March 31, 2001, the three months ended March 31, 2000 or March 31, 1999, and the years ended December 31, 1999 or 1998. Taxes, other than income taxes, charged to operating expenses are set forth by class as follows:

	Year Ended March 31, 2001	Three Months Ended March 31,		Year Ended December 31,	
(In thousands)		2000	1999 (unaudited)	1999	1998
Municipal property taxes	**$19,334**	$4,718	$4,618	$17,640	$42,080
Federal and state payroll and other taxes	**3,009**	843	1,016	2,642	6,412
	$22,343	$5,561	$5,634	$20,282	$48,492

Transactions between the Company and other affiliated companies for sales of electric energy and other sales amounted to approximately $385,982,000, $90,934,000, $120,700,000, $338,295,000, and $1,077,752,000 for the year ended March 31, 2001, the three months ended March 31, 2000, the three months ended March 31, 1999, and the years ended December 31, 1999 and 1998, respectively.

National Grid USA Service Company, Inc., 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 $44,315,000, $11,514,000, $10,088,000, $43,584,000, and $74,203,000, including capitalized construction costs of $19,117,000, $4,597,000, $3,415,000, $17,229,000, and $21,281,000, in the year ended March 31, 2001, the three months ended March 31, 2000, the three months ended March 31, 1999, and the years ended December 31, 1999 and 1998, respectively.

New England Power Company

Selected Financial Information

(In millions)	Year Ended March 31, 2001	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997	Year Ended December 31, 1996
Operating revenue	$ 656	$ 135	$ 167	$ 596	$1,218	$1,678	$1,600
Net income	$ 58	$ 14	$ 20	$ 71	$ 123	$ 145	$ 152
Total assets	$2,889	$2,630	$2,282	$2,303	$2,415	$2,763	$2,648
Capitalization:							
Common equity	$ 865	$ 657	$ 523	$ 332	$ 521	$ 913	$ 906
Cumulative preferred stock	1	1	1	2	1	40	40
Long-term debt	410	372	372	372	372	648	733
Total capitalization	$1,276	$1,030	$ 896	$ 706	$ 894	$1,601	$1,679
Preferred dividends declared	$ -	$ -	$ -	$ -	$ 1	$ 2	$ 3
Common dividends declared	$ -	$ 24	$ -	$ 241	$ 131	$ 135	$ 134

Selected Quarterly Financial Information (Unaudited)

(In thousands)	Quarter Ended March 31, 2000	Quarter Ended June 30, 2000	Quarter Ended Sept. 30, 2000	Quarter Ended Dec. 31, 2000	Quarter Ended March 31, 2001
Operating revenue	$134,564	$156,190	$175,390	$156,396	$168,296
Operating income	$ 16,685	$ 15,908	$ 25,232	$ 22,040	$ 24,535
Net income	$ 14,462	$ 14,223	$ 16,460	$ 14,780	$ 12,837

(In thousands)	Quarter Ended March 31, 1999	Quarter Ended June 30, 1999	Quarter Ended Sept. 30, 1999	Quarter Ended Dec. 31, 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

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

Transitional Period Annual Report 2000

New England Power Company

National Grid

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 of 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 March 31, 2000 and December 31, 1999 and 1998, and the results of its operations and its cash flows for the three months ended March 31, 2000 and 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

June 20, 2000

New England Power Company
Financial Review

Merger 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. National Grid paid a total of $4 billion, including $3.2 billion in cash paid to shareholders pursuant to the merger agreement, $642 million for National Grid USA's merger with Eastern Utilities Associates (EUA) (discussed below), an additional capital contribution of $141 million, and merger related expenses of $37 million. New England Power Company (the Company) will maintain its existing name and will remain a wholly owned subsidiary of National Grid USA.

The merger of National Grid USA and National Grid has been accounted for as an acquisition of National Grid USA by National Grid using the purchase method of accounting. The application of the purchase method, including the recognition of goodwill, is being pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $1.7 billion, of which the Company was allocated $334.1 million at the date of the merger. This amount was determined pursuant to an independent study conducted by a third party and is being amortized over 20 years. The annual amortization expense will amount to approximately $16.7 million.

The purchase accounting method requires the Company to revalue its assets and liabilities at their fair value. This revaluation resulted in a net debit adjustment to the Company's pension and postretirement benefit plans in the amount of approximately $61 million, with a corresponding offsetting credit to a regulatory liability account (see Note E of the Notes to Financial Statements).

Merger with EUA

The merger between the National Grid USA and EUA parent companies was completed on April 19, 2000, with EUA merging into National Grid USA. The impacts of this transaction will be reflected in subsequent reporting periods. The price paid by National Grid USA was $642 million, or $31.459 per share. On May 1, 2000, Montaup Electric Company (Montaup), formerly a subsidiary of EUA, merged into the Company.

The merger of EUA and National Grid USA 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 financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $388 million, of which the Company was allocated $7.7 million. This amount was determined pursuant to an independent study conducted by a third party and is being amortized over 20 years. The annual amortization expense will amount to approximately $0.4 million.

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), all customers were granted choice of power supplier in 1998. To facilitate the implementation of customer choice, the settlement agreements provided for the amendment of the Company's all-requirements contracts with its affiliated distribution companies. The Company's all-requirements contracts with some unaffiliated customers were terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service at fixed rates to some new customer load in Rhode Island. In addition, as a result of the Settlement Agreements, the Company and its affiliate, The Narragansett Electric Company (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 March 31, 2000 of approximately $687 million) toward the above-market cost of those contracts. The Company has recorded a corresponding current liability of $75 million, and a long-term liability of $612 million. 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 at date of purchase, which corresponds to approximately $290 million at March 31, 2000), which were separate from the $687 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 with which it has settlement agreements 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. The Company's 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 or liabilities, 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 Federal Energy Regulatory Commission (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 March 31, 2000, 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 other net CTC-related regulatory assets.

Impact of Mergers on Transmission and CTC Rates

Under a rate consolidation plan accepted by the FERC in September 1999, upon National Grid USA's acquisition of EUA and the merger of Montaup, EUA's transmission company, into the Company on May 1, 2000, the combined company charges a single system open access transmission tariff based upon its total transmission costs. Montaup will charge a separate CTC rate until a rate for the combined company is established.

Change of Fiscal Year

National Grid USA and its subsidiaries, including the Company, changed their fiscal year from a calendar year ending December 31 to a fiscal year ending March 31. The Company made this change in order to align its fiscal year with that of National Grid USA's parent company, National Grid. The Company's first new full fiscal year began on April 1, 2000 and will end on March 31, 2001. The Company has reported results of operations for the three month transitional period ended March 31, 2000, the three month period ended March 31, 1999, and the years ended December 31, 1999, December 31, 1998, and December 31, 1997. The Company has also reported balance sheets as of March 31, 2000, December 31, 1999, and December 31, 1998, and statements of cash flows for the three month periods ended March 31, 2000, and March 31, 1999, and the years ended December 31, 1999, December 31, 1998, and December 31, 1997.

Overview of Financial Results

Net income for the three months ended March 31, 2000 decreased $6 million compared with the same period in 1999 primarily due to the elimination of certain liabilities related to open access transmission tariffs of approximately $5 million in the first quarter of 1999.

Net income for the year ended December 31, 1999 decreased $52 million compared with the same period in 1998 as a result of the continuing impacts of the divestiture and the restructuring of the utility business. Partially offsetting the decrease was 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 the year ended December 31, 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 the three months ended March 31, 2000 decreased $33 million compared with the same period in 1999, largely due to CTC revenue of approximately $21 million from Narragansett Electric in 1999 related to its access charge overcollections. This payment reduced Narragansett Electric's future CTC obligations. This additional revenue in 1999 had a corresponding impact to the amortization of CTC, discussed in "Operating Expenses" below. The decrease is also due to the elimination of certain liabilities related to open access transmission tariffs of $5 million in 1999. This decrease is partially offset by the impacts of increased standard offer rates effective January 1, 2000 and increased kilowatthour sales in the three months ended March 31, 2000 compared with the same period in 1999.

Operating revenue for the year ended December 31, 1999 decreased $622 million compared with 1998 due to the divestiture and reduced CTC charges. Partially offsetting this decrease was an increase in transmission revenues associated with the elimination of certain liabilities related to open access transmission tariffs discussed above.

Operating revenue for the year ended December 31, 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 the three months ended March 31, 2000 decreased $27 million compared with the same period in 1999.

The increase in fuel and purchased power expense of approximately $5 million reflects increased purchased power expenses for standard offer requirements and increased kilowatthours purchased.

Other operating expenses in the three months ended March 31, 2000 decreased approximately $3 million compared with the same period in 1999 due to the reimbursement of start-up costs from 1999 of the Independent System Operator - New England (ISO New England) in 2000. Maintenance expenses decreased approximately $1 million as a result of reduced expenses at the partially owned Millstone 3 and Seabrook 1 nuclear generating facilities.

Depreciation and amortization expenses in the three months ended March 31, 2000 decreased $23 million compared with the same period in 1999. This decrease is due to additional CTC amortization in 1999 related to the additional payment of approximately $21 million by Narragansett Electric to the Company, discussed above.

Operating expenses for the year ended December 31, 1999 decreased $543 million compared with 1998. The divestiture reduced all categories of operating expenses in 1999, with the exception of depreciation and amortization expense.

The decrease in fuel expense and purchased power costs reflected 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 reflected 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 ISO 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 the year ended December 31, 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 the years ended December 31, 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 was also due to new transmission plant expenditures.

Interest Expense and Other Income

The increase in interest expense for the three months ended March 31, 2000 is primarily due to increased interest rates on variable rate long-term debt and interest on short-term debt borrowings not present in 1999.

The increase in other income for the three months ended March 31, 2000 is primarily due to decreased expenses related to employee incentive plans from workforce reductions following the divestiture, partially offset by merger related expenses in 2000.

The decrease in interest expense in the years ended December 31, 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 the years ended December 31, 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, including Montaup's portion effective with the EUA merger, are as follows:

Unit	The Company's Investment as of 3/31/00 %	$(millions)	Date Retired	Future Estimated Billings to the Company $(millions)
Yankee Atomic	30	4	Feb 1992	4
Connecticut Yankee	15	16	Dec 1996	60
Maine Yankee	20	15	Aug 1997	124

Unit	Montaup's Investment as of 3/31/00 %	$(millions)	Date Retired	Future Estimated Billings to Montaup $(millions)
Yankee Atomic	4.5	1	Feb 1992	1
Connecticut Yankee	4.5	5	Dec 1996	19
Maine Yankee	4.0	3	Aug 1997	26

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 arguing that Connecticut Yankee was entitled to recover only those costs directly related to decommissioning, but should not recover any remaining unamortized investment or return on equity. 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 (including Montaup's) of the loss of the return component would total approximately $16 million to $20 million before taxes for the entire recovery period. In April 2000, a settlement was reached among Connecticut Yankee, the Connecticut Department of Public Utility Control (CDPUC), the Office of Consumer Counsel (OCC), and the Connecticut Municipal Electric Cooperative. The settlement resolves all issues in the case, except the OCC has reserved its right to appeal recovery of any costs other than decommissioning. Billings will be reduced prospectively. There will be no refund of any amounts collected up to the effective date of the settlement. Connecticut Yankee had reserved for potential refunds and will be reversing that reserve. Prospectively, Connecticut Yankee has agreed to reduce annual collections for decommissioning through the use of its pre-1983 spent fuel trust funds and to limit its return on equity to 6 percent. In addition, Connecticut Yankee has pursued litigation against the Department of Energy to assume financial responsibility for storage of spent nuclear fuel and has agreed to pass to ratepayers any recovery after litigation expenses. The settlement is pending before the FERC.

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.

Maine Yankee had hired Stone & Webster, Inc., an engineering, construction, and consulting company, as the principal contractor to decommission the unit. Stone & Webster recently announced plans to file for Chapter 11 bankruptcy protection due to financial difficulties. Stone & Webster also announced that it has negotiated the sale of substantially all of its assets. In May 2000, Maine Yankee terminated its long-term contract with Stone & Webster and negotiated an arrangement with Stone & Webster to continue work until June 2000. On June 2, 2000, Stone & Webster filed for Chapter 11 bankruptcy protection. Maine Yankee is considering its options for decommissioning the unit beyond June 30, 2000. At this time, the Company is unable to determine the potential impact, if any, of this development.

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 Nuclear Regulatory Commission (NRC) scrutiny. The Company performs periodic economic viability reviews of operating nuclear units in which it holds ownership interests. 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.

Vermont Yankee

The following tables summarize the interests of the Company, and of Montaup (effective with the EUA merger), in the Vermont Yankee Nuclear Power Corporation as of March 31, 2000:

	The Company's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
20	$11	$33	$86	$43	2012

	Montaup's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
2.5	$1	$4	$11	$5	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 an 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 Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935 (1935 Act), and the Vermont Public Service Board (VPSB), among others. The Vermont Public Service Department has identified several issues that must be resolved to its satisfaction for it to support the VPSB's approval of the sale.

Millstone 3

In August 1997, the Company sued Northeast Utilities (NU) in Massachusetts Superior Court for damages, alleging that NU engaged in tortious conduct that caused the shutdown of Millstone 3, which is operated by a subsidiary of NU. 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, seeking damages for breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3. In July 1998, Millstone 3 returned to full operation after being shut down for more than two years.

In November 1999, the Company executed an agreement which settled the litigation and arbitration. Under the settlement agreement, the NU companies paid the Company $23.7 million and paid Montaup $7.8 million. The settlement also includes an agreement by NU to include the Company's and Montaup's share of Millstone 3 in an auction of NU's share of the unit. Upon the closing of the sale, NU will pay the Company and Montaup a combined total of $25 million, regardless of the actual sale price, and reimburse the Company and Montaup for any capital expenditures in excess of pre-budgeted levels incurred after October 1999. The Company and

Montaup will also be reimbursed for fuel procurement expenditures which increase net nuclear fuel account balances above current balances. The settlement also requires NU to indemnify the Company and Montaup and assume any residual liabilities resulting from the sale, including any requirements that the sellers continue to purchase output from the unit. In addition, the settlement requires NU to pay the Company and Montaup an additional combined total of $1 million per month for every month beyond April 1, 2001 that the closing does not occur. The auction process is being conducted by the CDPUC and is ongoing. 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.

Seabrook 1

As part of its restructuring settlement with the State of New Hampshire, Public Service Company of New Hampshire (PSNH), through its affiliate, North Atlantic Energy Corporation (NAEC), has committed to seek New Hampshire Public Utilities Commission (NHPUC) approval of a definitive plan to sell, via public auction, its share of Seabrook 1, with such sale to occur no later than December 31, 2003. NAEC is the majority owner of the plant with a 35.98 percent interest and is also the plant operator. As part of its settlement, PSNH has also agreed to make all reasonable efforts to bundle its interests with those of other owners (including the Company) seeking to sell their interests. This would allow for an auction of a majority interest. The NHPUC granted conditional approval of the settlement on April 19, 2000. The New Hampshire legislature approved the necessary legislation on May 31, 2000. Final resolution by the NHPUC approving the settlement in compliance with the legislation is expected this summer.

Year 2000 Disclosure

In 1999, National Grid USA and its subsidiaries completed their remediation of the potential 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, National Grid USA and its subsidiaries have experienced no significant disruptions in any of their enterprise or operational computer systems.

National Grid USA's and its subsidiaries' costs of making the necessary Y2K modifications were approximately $28 million. In addition, National Grid USA and its subsidiaries 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 March 31, 2000, the Company's variable rate long-term debt had a carrying value and fair value of approximately $372 million and maturity dates greater than five years. The weighted average variable interest rate for the three months ended March 31, 2000, was 3.75 percent.

As discussed in the "Industry Restructuring" section, the Company remains obligated to provide transition power supply service at fixed rates to some new customer load in Rhode Island. The Company meets this obligation 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 over the term of the obligation. In the short term, it appears that due to current high market prices, it is probable the Company will incur losses this summer. At this point, management cannot reasonably estimate the level of such losses.

Utility Plant Expenditures and Financing

Cash expenditures for the Company for utility plant totaled $12 million for the three months ended March 31, 2000 and were primarily transmission-related. The funds necessary for utility plant expenditures during the period were primarily provided by internal funds. Cash expenditures for fiscal year 2001 for the Company and Montaup are estimated to be approximately $45 million, principally related to transmission functions. Internally generated funds are expected to fully cover capital expenditures in fiscal year 2001.

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.

Dividends payable at March 31, 2000, in the amount of $256 million were paid on June 27, 2000.

The Company has regulatory approval to issue up to $375 million of short-term debt. In 1999, the Company issued $39 million of short-term tax-exempt debt. This debt remains outstanding as of March 31, 2000. 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 March 31, 2000, 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 March 31, 2000.

New England Power Company
Statements of Income

(In thousands)	3 Months ended March 31, 2000	3 Months ended March 31, 1999 (unaudited)	Year ended December 31, 1999	Year ended December 31, 1998	Year ended December 31, 1997
Operating revenue, principally from affiliates	$134,564	$167,177	$ 596,341	$1,218,340	$1,677,903
Operating expenses:					
Fuel for generation	3,548	3,058	12,803	223,828	372,734
Purchased electric energy:					
Contract termination and nuclear unit shutdown charges	47,405	46,873	187,777	97,469	43,876
Other	14,682	11,111	56,731	302,367	483,771
Other operation	15,760	19,210	70,936	155,065	241,506
Maintenance	4,320	5,766	28,536	60,239	89,820
Depreciation and amortization	17,328	40,367	103,080	99,924	98,024
Taxes, other than income taxes	5,561	5,634	20,282	48,492	67,311
Income taxes	9,641	13,100	37,633	73,594	90,009
Total operating expenses	118,245	145,119	517,778	1,060,978	1,487,051
Operating income	16,319	22,058	78,563	157,362	190,852
Other income:					
Allowance for equity funds used during construction	(393)	588	1,958	633	-
Equity in income of nuclear power companies	862	515	2,939	5,284	5,189
Other income (expense), net	1,850	434	2,087	118	(3,404)
Operating and other income	18,638	23,595	85,547	163,397	192,637
Interest:					
Interest on long-term debt	3,749	3,143	14,052	30,775	42,277
Other interest	853	240	1,003	10,688	7,055
Allowance for borrowed funds used during construction	(426)	(133)	(522)	(961)	(1,238)
Total interest	4,176	3,250	14,533	40,502	48,094
Net income	$ 14,462	$ 20,345	$ 71,014	$ 122,895	$ 144,543

Statements of Retained Earnings

(In thousands)	3 Months ended March 31, 2000	3 Months ended March 31, 1999 (unaudited)	Year ended December 31, 1999	Year ended December 31, 1998	Year ended December 31, 1997
Retained earnings at beginning of period	$ 27,287	$204,603	$ 204,603	$ 407,630	$ 400,610
Net income	14,462	20,345	71,014	122,895	144,543
Dividends declared on cumulative preferred stock	(24)	(24)	(94)	(1,230)	(2,075)
Dividends declared on common stock, $6.66, $-0-, $66.69, $20.25, and $21.00 per share, respectively	(24,098)	-	(241,415)	(130,610)	(135,448)
Premium on redemption of preferred stock	-	-	264	(264)	-
Repurchase of common stock	-	(7,085)	(7,085)	(193,818)	-
Purchase accounting adjustment	(16,212)	-	-	-	-
Retained earnings at end of period	$ 1,415	$217,839	$ 27,287	$ 204,603	$ 407,630

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

New England Power Company
Balance Sheets

(In thousands)	At March 31, 2000	At December 31, 1999	1998
Assets			
Utility plant, at original cost	$1,318,026	$1,312,384	$1,262,461
Less accumulated provisions for depreciation and amortization	854,309	849,694	837,637
	463,717	462,690	424,824
Construction work in progress	35,730	30,063	33,289
Net utility plant	499,447	492,753	458,113
Total goodwill, net of amortization	333,771	-	-
Investments:			
Nuclear power companies, at equity (Note D-1)	45,966	46,233	48,538
Decommissioning trust funds (Note D-2)	36,279	36,279	31,281
Nonutility property and other investments	7,490	7,248	8,302
Total investments	89,735	89,760	88,121
Current assets:			
Cash and temporary cash investments (including $37,820, $59,039, and $109,911 with affiliates)	226,921	204,344	179,413
Accounts receivable:			
Affiliated companies	72,780	73,444	107,878
Others	48,139	44,301	32,573
Fuel, materials, and supplies, at average cost	10,345	9,471	9,220
Prepaid and other current assets	25,377	39,315	21,569
Regulatory asset purchased power obligations	74,988	73,369	128,931
Total current assets	458,550	444,244	479,584
Regulatory assets (Note C)	1,210,800	1,272,463	1,383,631
Deferred charges and other assets	37,271	3,445	5,339
	$2,629,574	$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, 3,619,896, and 3,749,896 shares	$ 72,398	$ 72,398	$ 74,998
Premium on capital stock	-	48,623	50,371
Other paid-in capital (Note J)	582,983	183,937	190,852
Retained earnings	1,415	27,287	204,603
Unrealized gain on securities, net	-	91	72
Total common equity	656,796	332,336	520,896
Cumulative preferred stock, par value $100 per share (Note H)	1,567	1,567	1,567
Long-term debt	371,773	371,771	371,765
Total capitalization	1,030,136	705,674	894,228
Current liabilities:			
Short-term debt	38,500	38,500	-
Accounts payable (including $26,993, $25,620, and $119,657 to affiliates)	51,584	63,212	162,360
Accrued liabilities:			
Taxes	2,394	3,889	15,009
Interest	1,900	3,378	2,440
Purchased power contract obligations	74,988	73,369	128,931
Other accrued expenses (Note G)	10,879	15,693	20,086
Dividends payable	256,487	232,365	24
Total current liabilities	436,732	430,406	328,850
Deferred federal and state income taxes	176,351	179,686	165,115
Unamortized investment tax credits	16,733	19,060	30,870
Accrued Yankee nuclear plant costs (Note D-2)	268,855	277,932	242,138
Purchased power obligations	611,802	630,368	703,737
Other reserves and deferred credits	88,965	59,539	49,850
Commitments and contingencies (Note D)			
	$2,629,574	$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

(In thousands)	3 Months ended March 31, 2000	3 Months ended March 31, 1999 (unaudited)	Year ended December 31, 1999	Year ended December 31, 1998	Year ended December 31, 1997
Operating activities:					
Net income	$ 14,462	$ 20,345	$ 71,014	$ 122,895	$ 144,543
Adjustments to reconcile net income to net cash provided by operating activities:					
Depreciation and amortization	19,165	42,170	108,789	104,331	101,186
Deferred income taxes and investment tax credits, net	(2,908)	5,726	14,111	(226,722)	(12,728)
Allowance for funds used during construction	(33)	(720)	(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	(3,174)	37,890	22,706	130,914	(25,128)
Decrease (increase) in fuel, materials, and supplies	(874)	648	(251)	(10,270)	11,217
Decrease (increase) in regulatory asset purchased power obligations	(1,619)	19,956	55,562	(128,931)	-
Decrease (increase) in prepaid and other current assets	13,938	6,154	(17,746)	(8,778)	7,213
Increase (decrease) in accounts payable	(11,628)	(81,950)	(99,148)	(31,761)	(18,105)
Increase (decrease) in current purchased power contract payable	1,619	(19,956)	(55,562)	128,931	-
Increase (decrease) in other current liabilities	(7,787)	(11,147)	(14,575)	5,037	(1,905)
Other, net	13,577	(709)	(3,995)	(49,611)	19,919
Net cash provided by (used in) operating activities	$ 34,738	$ 18,407	$ 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	(11,890)	$(13,739)	(56,887)	(64,446)	(69,863)
Other investing activities	(271)	(20)	(4,411)	(5,474)	(4,040)
Net cash provided by (used in) investing activities	$(12,161)	$(13,759)	$(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	-	(24)	(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)	(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	$ -	$(18,080)	$ 11,276	$(1,028,124)	$(152,474)
Net increase (decrease) in cash and cash equivalents	$ 22,577	$(13,432)	$ 24,931	$ 177,770	$ (1,403)
Cash and cash equivalents at beginning of period	204,344	179,413	179,413	1,643	3,046
Cash and cash equivalents at end of period	$226,921	$165,981	$204,344	$ 179,413	$ 1,643
Supplementary Information:					
Interest paid less amounts capitalized	$ 5,322	$ 2,042	$ 11,849	$ 43,419	$ 46,033
Federal and state income taxes paid	$ (15)	$ 11,321	$ 55,134	$ 282,076	$ 109,109
Dividends received from investments at equity	$ 1,129	$ 1,730	$ 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. Change of Fiscal Year:

National Grid USA and its subsidiaries, including the Company, changed their fiscal year from a calendar year ending December 31 to a fiscal year ending March 31. The Company made this change in order to align its fiscal year with that of National Grid USA's parent company, The National Grid Group plc (National Grid). The Company's first new full fiscal year began on April 1, 2000 and will end on March 31, 2001. The Company has reported results of operations for the three month transitional period ended March 31, 2000, the three month period ended March 31, 1999, and the years ended December 31, 1999, December 31, 1998, and December 31, 1997. The Company has also reported balance sheets as of March 31, 2000, December 31, 1999, and December 31, 1998, and statements of cash flows for the three month periods ended March 31, 2000, and March 31, 1999, and the years ended December 31, 1999, December 31, 1998, and December 31, 1997.

3. 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 current presentation.

4. 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 3.7 percent for the three month period ended March 31, 2000, 8.1 percent for the three month period ended March 31, 1999, and 7.6 percent, 6.1 percent, and 5.9 percent for the years ended December 31, 1999, 1998, and 1997, respectively.

5. Depreciation and Amortization:

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

(In thousands)	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997
Depreciation - transmission related	$ 3,269	$ 3,440	$ 13,222	$12,553	$11,828
Depreciation - all other	(15)	354	1,286	46,256	68,432
Nuclear decommissioning costs (Note D-2)	923	699	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)	12,785	35,874	84,935	16,356	-
Goodwill	366	-	-	-	-
Total depreciation and amortization expense	$17,328	$40,367	$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 for the three month periods ended March 31, 2000, and March 31, 1999, and the years ended December 31, 1999, 1998, and 1997. Amortization of Seabrook and Millstone investments above normal depreciation accruals and amortization of regulatory assets covered by contract termination charges (CTC) was in accordance with rate settlement agreements.

The Company will amortize goodwill associated with the mergers of National Grid and National Grid USA, and National Grid USA and Eastern Utilities Associates (EUA) over a 20 year period on a straight line basis.

6. Cash:

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

Note B - Mergers with National Grid and EUA

Merger with National Grid

On March 22, 2000, the merger of NEES and National Grid was completed, with NEES (renamed National Grid USA) becoming a wholly owned subsidiary of National Grid. National Grid paid a total of $4 billion, including $3.2 billion in cash paid to shareholders pursuant to the merger agreement, $642 million for National Grid USA's merger with EUA (discussed below), an additional capital contribution of $141 million, and merger related expenses of $37 million. The Company will maintain its existing name and will remain a wholly owned subsidiary of National Grid USA.

The merger of National Grid USA and National Grid has been accounted for as an acquisition of National Grid USA by National Grid using the purchase method of accounting. The application of the purchase method, including the recognition of goodwill, is being pushed down and reflected on the financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $1.7 billion, of which the Company was allocated $334.1 million at the date of the merger. This amount was determined pursuant to an independent study conducted by a third party and is being amortized over 20 years. The annual amortization expense will amount to approximately $16.7 million.

The purchase accounting method requires the Company to revalue its assets and liabilities at their fair value. This revaluation resulted in a net debit adjustment to the Company's pension and postretirement benefit plans in the amount of approximately $61 million, with a corresponding offsetting credit to a regulatory liability account (see Note E).

Merger with EUA

The merger between the National Grid USA and EUA parent companies was completed on April 19, 2000, with EUA merging into National Grid USA. The impacts of this transaction will be reflected in subsequent reporting periods. The price paid by National Grid USA was $642 million, or $31.459 per share. On May 1, 2000, Montaup Electric Company (Montaup), formerly a subsidiary of EUA, merged into the Company.

The merger of EUA and National Grid USA 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 financial statements of the National Grid USA subsidiaries, including the Company. Total goodwill amounted to $388 million, of

which the Company was allocated $7.7 million. This amount was determined pursuant to an independent study conducted by a third party and is being amortized over 20 years. The annual amortization expense will amount to approximately $0.4 million.

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), all customers were granted choice of power supplier in 1998. To facilitate the implementation of customer choice, the Settlement Agreements provided for the amendment of the Company's all-requirements contracts with its affiliated distribution companies. The Company's all-requirements contracts with some unaffiliated customers were terminated pursuant to settlement agreements or tariff provisions. However, the Company remains obligated to provide transition power supply service at fixed rates to some 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 March 31, 2000 of approximately $687 million) toward the above-market cost of those contracts. The Company has recorded a corresponding current liability of $75 million, and a long-term liability of $612 million. 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 at date of purchase, which corresponds to approximately $290 million at March 31, 2000), which were separate from the $687 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 with which it has settlement agreements 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. The Company's 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 or liabilities, 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 March 31, 2000, 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 other net CTC-related regulatory assets.

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)	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997
Operating revenue	$ 81,225	$ 89,244	$ 377,039	$ 439,046	$ 660,742
Net income	$ 5,310	$ 5,138	$ 13,890	$ 23,218	$ 29,959
Company's equity in net income	$ 862	$ 515	$ 2,939	$ 5,284	$ 5,189
Net plant	167,317	166,062	172,100	171,582	204,689
Other assets	2,520,887	2,798,948	2,631,750	2,810,613	3,100,589
Liabilities and debt	(2,437,609)	(2,707,749)	(2,554,261)	(2,723,454)	(3,036,845)
Net assets	$ 250,595	$ 257,261	$ 249,589	$ 258,741	$ 268,433
Company's equity in net assets	$ 45,966	$ 47,323	$ 46,233	$ 48,538	$ 49,825
Company's purchased electric energy:					
Vermont Yankee	$ 7,761	$ 7,874	$ 37,551	$ 35,108	$ 31,240
All other Yankees	$ 9,324	$ 9,370	$ 37,765	$ 48,543	$ 75,900

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, including Montaup's portion effective with the EUA merger, are as follows:

Unit	The Company's Investment as of 3/31/00 %	$(millions)	Date Retired	Future Estimated Billings to the Company $(millions)
Yankee Atomic	30	4	Feb 1992	4
Connecticut Yankee	15	16	Dec 1996	60
Maine Yankee	20	15	Aug 1997	124

Unit	Montaup's Investment as of 3/31/00 %	$(millions)	Date Retired	Future Estimated Billings to Montaup $(millions)
Yankee Atomic	4.5	1	Feb 1992	1
Connecticut Yankee	4.5	5	Dec 1996	19
Maine Yankee	4.0	3	Aug 1997	26

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 arguing that Connecticut Yankee was entitled to recover only those costs directly related to decommissioning, but should not recover any remaining unamortized investment or return on equity. 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

(including Montaup's) of the loss of the return component would total approximately $16 million to $20 million before taxes for the entire recovery period. In April 2000, a settlement was reached among Connecticut Yankee, the Connecticut Department of Public Utility Control (CDPUC), the Office of Consumer Counsel (OCC), and the Connecticut Municipal Electric Cooperative. The settlement resolves all issues in the case, except the OCC has reserved its right to appeal recovery of any costs other than decommissioning. Billings will be reduced prospectively. There will be no refunds of any amounts collected up to the effective date of the settlement. Connecticut Yankee had reserved for potential refunds and will be reversing that reserve. Prospectively, Connecticut Yankee has agreed to reduce annual collections for decommissioning through the use of its pre-1983 spent fuel trust funds and to limit its return on equity to 6 percent. In addition, Connecticut Yankee has pursued litigation against the Department of Energy (DOE) to assume financial responsibility for storage of spent nuclear fuel and has agreed to pass to ratepayers any recovery after litigation expenses. The settlement is pending before the FERC.

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.

Maine Yankee had hired Stone & Webster, Inc., an engineering, construction, and consulting company, as the principal contractor to decommission the unit. Stone & Webster recently announced plans to file for Chapter 11 bankruptcy protection due to financial difficulties. Stone & Webster also announced that it has negotiated the sale of substantially all of its assets. In May 2000, Maine Yankee terminated its long-term contract with Stone & Webster and negotiated an arrangement with Stone & Webster to continue work until June 2000. On June 2, 2000, Stone & Webster filed for Chapter 11 bankruptcy protection. Maine Yankee is considering its options for decommissioning the unit beyond June 30, 2000. At this time, the Company is unable to determine the potential impact, if any, of this development.

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. 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.

Vermont Yankee

The following tables summarize the interests of the Company, and of Montaup (effective with the EUA merger), in the Vermont Yankee Nuclear Power Corporation as of March 31, 2000:

	The Company's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
20	$11	$33	$86	$43	2012

	Montaup's Interest (millions of dollars)				
Equity Ownership Interest (%)	Equity Investment	Net Plant Assets	Estimated Decommissioning Cost (in 1999$)	Decommissioning Fund Balance	License Expiration
2.5	$1	$4	$11	$5	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 an 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 Vermont Public Service Board (VPSB), among others. The Vermont Public Service Department has identified several issues that must be resolved to its satisfaction for it to support the VPSB's approval of the sale.

Millstone 3

In August 1997, the Company sued Northeast Utilities (NU) in Massachusetts Superior Court for damages, alleging that NU engaged in tortious conduct that caused the shutdown of Millstone 3, which is operated by a subsidiary of NU. 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, seeking damages for breach of obligations under an agreement with the Company and others regarding the operation and ownership of Millstone 3. In July 1998, Millstone 3 returned to full operation after being shut down for more than two years.

In November 1999, the Company executed an agreement which settled the litigation and arbitration. Under the settlement agreement, the NU companies paid the Company $23.7 million and paid Montaup $7.8 million. The settlement also includes an agreement by NU to include the Company's and Montaup's share of Millstone 3 in an auction of NU's share of the unit. Upon the closing of the sale, NU will pay the Company and Montaup a combined total of $25 million, regardless of the actual sale price, and reimburse the Company and Montaup for any capital expenditures in excess of pre-budgeted levels incurred after October 1999. The Company and Montaup will also be reimbursed for fuel procurement expenditures which increase net nuclear fuel account balances above current balances. The settlement also requires NU to indemnify the Company and Montaup and assume any residual liabilities resulting from the sale, including any requirements that the sellers continue to purchase output from the unit. In addition, the settlement requires

NU to pay the Company and Montaup an additional combined total of $1 million per month for every month beyond April 1, 2001 that the closing does not occur. The auction process is being conducted by the CDPUC and is ongoing. 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.

Seabrook 1

As part of its restructuring settlement with the State of New Hampshire, Public Service Company of New Hampshire (PSNH), through its affiliate, North Atlantic Energy Corporation (NAEC), has committed to seek New Hampshire Public Utilities Commission (NHPUC) approval of a definitive plan to sell, via public auction, its share of Seabrook 1, with such sale to occur no later than December 31, 2003. NAEC is the majority owner of the plant with a 35.98 percent interest and is also the plant operator. As part of its settlement, PSNH has also agreed to make all reasonable efforts to bundle its interests with those of other owners (including the Company) seeking to sell their interests. This would allow for an auction of a majority interest. The NHPUC granted conditional approval of the settlement on April 19, 2000. The New Hampshire legislature approved the necessary legislation on May 31, 2000. Final resolution by the NHPUC approving the settlement in compliance with the legislation is expected this summer.

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 and these costs are recorded as 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 15 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 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 and Montaup have 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 tables below list information on the operating nuclear plants in which the Company and Montaup are joint owners.

	The Company's share of (millions of dollars)				
Unit	The Company's Ownership Interest (%)	Net Plant Assets (at 3/31/00)	Estimated Decommissioning Cost (in 1999 $)	Decommissioning Fund Balances* (at 3/31/00)	License Expiration
Millstone 3	12	12**	76	23	2025
Seabrook 1	10	14**	56	13	2026

	Montaup's share of (millions of dollars)				
Unit	The Company's Ownership Interest (%)	Net Plant Assets (at 3/31/00)	Estimated Decommissioning Cost (in 1999 $)	Decommissioning Fund Balances* (at 3/31/00)	License Expiration
Millstone 3	4	4**	25	8	2025

*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 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 will gradually become unavailable to units other than Connecticut Yankee and Millstone 3. 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

Utility plant expenditures for the Company and Montaup are estimated to be approximately $45 million in fiscal year 2001.

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 (including Montaup's) at March 31, 2000, amounted to $24 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 the Company's hazardous waste liabilities for all sites of which the Company 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 March 2000, the charges assessed Norwood amount to approximately $18 million, all of which remain unpaid. The Company has filed 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) 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 alleged 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. On May 30, 2000, Norwood petitioned the US Supreme Court for review of the First Circuit decisions.

Norwood has also appealed a 1999 FERC decision that rejected Norwood's challenge to the calculation of the CTC based on the terms of the 1983 power contract. On June 12, 2000, Norwood moved to amend its complaint to reassert a claim for rescission with respect to the Company's divestiture. The Company has filed a motion to dismiss.

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 the three months ended March 31, 2000 and the years ended December 31, 1999, 1998, and 1997 included the following components:

	Three Months Ended March 31,	Year Ended December 31,		
(thousands of dollars)	2000	1999	1998	1997
Service cost - benefits earned during the period	$ 118	$ 527	$ 2,430	$ 2,887
Plus (less):				
Interest cost on projected benefit obligation	1,760	7,044	7,435	7,003
Return on plan assets at expected long-term rate	(2,200)	(8,090)	(8,675)	(7,842)
Amortization of transition obligation	(33)	(170)	(184)	(175)
Amortization of prior service cost	24	115	161	171
Amortization of net (gain)/loss	(100)	36	159	65
Curtailment (gain)/loss	-	-	(5,680)	-
Benefit cost	$ (431)	$ (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 March 31,	At December 31,	
(millions of dollars)	2000	1999	1998
Benefit obligation	$ 800	$ 789	$843
Unrecognized prior service costs	-	(5)	(6)
Transition liability not yet recognized (amortized)	-	(2)	(2)
Additional minimum liability	-	6	7
	800	788	842
Plan assets at fair value	991	947	837
Transition asset not yet recognized (amortized)	-	(5)	(6)
Net (gain)/loss not yet recognized (amortized)	-	(206)	(92)
	991	736	739
Accrued (prepaid) pension benefits recorded on National Grid USA books	$(191)	$ 52	$103

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

(millions of dollars)	At March 31, 2000	At December 31, 1999	1998
Changes in benefit obligation:			
Benefit obligation at January 1	$789	$843	$819
Service cost	2	11	14
Interest cost	15	56	55
Actuarial (gain)/loss	10	(55)	(5)
Benefits paid	(16)	(66)	(94)
Special termination benefits	-	-	64
Curtailment	-	-	(11)
Plan amendments	-	-	1
Benefit obligation end of period	$800	$789	$843
Reconciliation of change in plan assets:			
Fair value of plan assets at January 1	$947	$837	$834
Actual return on plan assets during year	59	117	93
Company contributions	1	59	4
Benefits paid from plan assets	(16)	(66)	(94)
Fair value of plan assets end of period	$991	$947	$837

	March 31, 2001	December 31, 2000	1999	1998	1997
Assumptions used to determine pension cost:					
Discount rate	7.75%	7.75%	6.75%	6.75%	7.25%
Average rate of increase in future compensation level	5.10%	5.10%	4.13%	4.13%	4.13%
Expected long-term rate of return on assets	8.50%	8.50%	8.50%	8.50%	8.50%

The plans' funded status at March 31, 2000 and December 31, 1999 and 1998 were calculated using the assumed rates from 2001, 2000, and 1999, respectively, and the 1983 Group Annuity Mortality table.

Plan assets are composed primarily of equity and fixed income securities. Fair value adjustments of approximately $33 million are reflected in the Company's financial statements.

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 the three months ended March 31, 2000 and the years ended December 31, 1999, 1998, and 1997 included the following components:

	Three Months Ended March 31,	Year Ended December 31,		
(thousands of dollars)	2000	1999	1998	1997
Service cost - benefits earned during the period	$ 47	$ 193	$ 1,109	$ 1,363
Plus (less):				
Interest cost on projected benefit obligation	786	2,816	3,244	3,545
Return on plan assets at expected long-term rate	(803)	(2,896)	(2,656)	(2,343)
Amortization of transition obligation	19	85	1,732	2,556
Amortization of prior service cost	-	-	5	8
Amortization of net (gain)/loss	(285)	(1,252)	(1,138)	(983)
Curtailment (gain)/loss	-	-	27,149	-
Benefit cost	$(236)	$(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, including fair value adjustments recorded in the first quarter of 2000 of approximately $28 million:

	At March 31,	At December 31,	
(millions of dollars)	2000	1999	1998
Benefit obligation	$38	$ 42	$ 41
Unrecognized prior service costs	-	-	-
Transition liability not yet recognized (amortized)	-	(1)	(1)
	38	41	40
Plan assets at fair value	40	39	36
Net (gain)/loss not yet recognized (amortized)	-	(25)	(26)
	40	14	10
Accrued (prepaid) PBOPs recorded on books	$(2)	$ 27	$ 30

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

(millions of dollars)	At March 31, 2000	At December 31, 1999	1998
Changes in benefit obligation:			
Benefit obligation at January 1	$42	$41	$ 51
Service cost	-	-	1
Interest cost	1	3	3
Actuarial (gain)/loss	(4)	-	2
Benefits paid	(1)	(2)	(2)
Special termination benefits	-	-	-
Curtailment	-	-	(14)
Benefit obligation end of year	$38	$42	$ 41
Reconciliation of change in plan assets:			
Fair value of plan assets at January 1	$39	$36	$ 34
Actual return on plan assets during year	2	4	4
Company contributions	-	1	-
Benefits paid from plan assets	(1)	(2)	(2)
Fair value of plan assets end of year	$40	$39	$ 36

	March 31, 2001	2000	December 31, 1999	1998	1997
Assumptions used to determine postretirement benefit cost:					
Discount rate	7.75%	7.75%	6.75%	6.75%	7.25%
Expected long-term rate of return on assets	8.40%	8.42%	8.35%	8.27%	8.21%
Health care cost rates:					
1997 to 1999			5.25%	5.25%	8.00%
2000	8.25%	8.25%	5.25%	5.25%	6.25%
2001	6.75%	6.75%	5.25%	5.25%	6.25%
2002 to 2004	5.25%	5.25%	5.25%	5.25%	6.25%
2005 and beyond	5.25%	5.25%	5.25%	5.25%	5.25%

The plans' funded status at March 31, 2000 and December 31, 1999 and 1998 were calculated using the assumed rates in effect for 2001, 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 March 31, 2000 by approximately $4 million or decrease the APBO by approximately $4 million, and change the net periodic cost for fiscal year 2001 by approximately $100,000.

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

3. 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 intend to elect to participate with National Grid General Partnership, National Grid USA's parent company that is wholly owned by National Grid, in filing a consolidated federal income tax return. 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:

(In thousands)	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997
Income taxes charged to operations	$9,641	$13,100	$37,633	$ 73,594	$90,009
Income taxes charged (credited) to "Other income"	(4)	-	1,985	(19,582)	(373)
Total income taxes	$9,637	$13,100	$39,618	$ 54,012	$89,636

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

(In thousands)	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997
Current income taxes	$12,545	$ 7,374	$ 25,507	$ 280,734	$102,364
Deferred income taxes	(581)	10,732	25,921	(204,129)	(10,705)
Investment tax credits, net	(2,327)	(5,006)	(11,810)	(22,593)	(2,023)
Total income taxes	$ 9,637	$13,100	$ 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:

(In thousands)	Three Months Ended March 31, 2000	1999 (unaudited)	Year Ended December 31, 1999	1998	1997
Federal income taxes	$8,035	$10,975	$33,746	$41,255	$73,077
State income taxes	1,602	2,125	5,872	12,757	16,559
Total income taxes	$9,637	$13,100	$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:

(In thousands)	Three Months Ended March 31, 2000	1999 (unaudited)	Year Ended December 31, 1999	1998	1997
Computed tax at statutory rate	$ 8,435	$11,706	$38,721	$ 61,917	$81,963
Increases (reductions) in tax resulting from:					
Amortization of investment tax credits	(1,513)	(3,254)	(7,677)	(15,157)	(2,023)
State income taxes, net of federal income tax benefit	1,042	1,381	3,817	8,292	10,763
Rate recovery of deficiency in deferred tax reserves	1,617	3,508	8,207	-	-
Prior year tax adjustment	-	-	(2,028)	(188)	(313)
All other differences	56	(241)	(1,422)	(852)	(754)
Total income taxes	$ 9,637	$13,100	$39,618	$ 54,012	$89,636

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

(In millions)	At March 31, 2000	At December 31, 1999	1998
Deferred tax asset:			
Plant related	$ 67	$ 67	$ 76
Investment tax credits	6	8	13
All other	3	2	24
	76	77	113
Deferred tax liability:			
Plant related	(159)	(157)	(53)
All other, principally regulatory assets	(93)	(100)	(225)
	(252)	(257)	(278)
Net deferred tax liability	$(176)	$(180)	$(165)

Note G - Short-term Borrowings and Other Accrued Expenses

At March 31, 2000, the Company had $39 million of short-term debt outstanding. The Company has regulatory approval 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 March 31, 2000, 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 March 31, 2000. Fees are paid on the lines and facilities in lieu of compensating balances.

The components of other accrued expenses are as follows:

(In thousands)	At March 31, 2000	At December 31, 1999	1998
Accrued wages and benefits	$ 1,215	$ 1,063	$ 3,059
Rate adjustment mechanisms	9,110	14,550	16,781
Other	554	80	246
	$10,879	$15,693	$20,086

Note H - Cumulative Preferred Stock

A summary of cumulative preferred stock at March 31, 2000 and December 31, 1999 and 1998 is as follows (in thousands of dollars except for share data):

	Shares Outstanding			Amount			Dividends Declared		
	2000	1999	1998	2000	1999	1998	2000	1999	1998
$100 par value									
6.00% Series	15,672	15,672	15,672	$1,567	$1,567	$1,567	$24	$94	$277
4.56% Series	-	-	-	-	-	-	-	-	247
4.60% Series	-	-	-	-	-	-	-	-	236
4.64% Series	-	-	-	-	-	-	-	-	98
6.08% Series	-	-	-	-	-	-	-	-	372
Total	15,672	15,672	15,672	$1,567	$1,567	$1,567	$24	$94	$1,230

The 6.00% Series cumulative preferred stock is noncallable.

The dividend requirement for cumulative preferred stock was $24,000 for the three months ended March 31, 2000, and the annual dividend requirement was $94,000 as of December 31, 1999. In 1998, the Company repurchased or redeemed preferred stock with an aggregate par value of $38 million. The preferred dividend requirement for 1998 was $1.2 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:

(In thousands)

Series	Rate %	Maturity	At March 31, 2000	At December 31, 1999	1998
Pollution Control Revenue Bonds:					
MIFA 1 (a)	variable	March 1, 2018	$ 79,250	$ 79,250	$ 79,250
BFA 1 (b)	variable	November 1, 2020	135,850	135,850	135,850
BFA 2 (b)	variable	November 1, 2020	50,600	50,600	50,600
MIFA 2 (a)	variable	October 1, 2022	106,150	106,150	106,150
Unamortized discounts			(77)	(79)	(85)
Total long-term debt			$371,773	$371,771	$371,765

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

At March 31, 2000, interest rates on the Company's variable rate long-term bonds ranged from 3.45 percent to 3.95 percent.

At March 31, 2000, 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 purchase accounting method was used in National Grid's merger with National Grid USA, which resulted in a purchase accounting adjustment of approximately $16 million to the Company's retained earnings to reflect post merger net income. This also resulted in a reduction to the premium on capital stock of $49 million, a reduction in the unrealized gain on securities - net of $73,000, and an increase of $399 million in other paid-in-capital due to the push down of goodwill.

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 the three months ended March 31, 2000, and March 31, 1999, and the years ended December 31, 1999, 1998, or 1997. Taxes, other than income taxes, charged to operating expenses are set forth by classes as follows:

(In thousands)	Three Months Ended March 31, 2000	Three Months Ended March 31, 1999 (unaudited)	Year Ended December 31, 1999	Year Ended December 31, 1998	Year Ended December 31, 1997
Municipal property taxes	$4,718	$4,618	$17,640	$42,080	$59,102
Federal and state payroll and other taxes	843	1,016	2,642	6,412	8,209
	$5,561	$5,634	$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 $11,514,000, $10,088,000, $43,584,000, $74,203,000, and $91,985,000, including capitalized construction costs of $4,597,000, $3,415,000, $17,229,000, $21,281,000, and $24,347,000, in the three months ended March 31, 2000, the three months ended March 31, 1999, and the years ended December 31, 1999, 1998, and 1997, respectively.

Selected Financial Information

(In millions)	Three Months Ended March 31, 2000	1999 (unaudited)	1999	Year Ended December 31, 1998	1997	1996	1995
Operating revenue	$ 135	$ 167	$ 596	$1,218	$1,678	$1,600	$1,571
Net income	$ 14	$ 20	$ 71	$ 123	$ 145	$ 152	$ 151
Total assets	$2,630	$2,282	$2,303	$2,415	$2,763	$2,648	$2,648
Capitalization:							
Common equity	$ 657	$ 523	$ 332	$ 521	$ 913	$ 906	$ 889
Cumulative preferred stock	1	1	2	1	40	40	61
Long-term debt	372	372	372	372	648	733	735
Total capitalization	$1,030	$ 896	$ 706	$ 894	$1,601	$1,679	$1,685
Preferred dividends declared	$ -	$ -	$ -	$ 1	$ 2	$ 3	$ 3
Common dividends declared	$ 24	$ -	$ 241	$ 131	$ 135	$ 134	$ 135

Selected Quarterly Financial Information (Unaudited)

(In thousands)	Three Months Ended March 31, 2000	First Quarter 1999	Second Quarter 1999	Third Quarter 1999	Fourth Quarter 1999
Operating revenue	$134,564	$167,177	$139,620	$142,066	$147,478
Operating income	$ 16,319	$ 22,058	$ 13,796	$ 18,782	$ 23,927
Net income	$ 14,462	$ 20,345	$ 14,254	$ 17,669	$ 18,746

	First Quarter 1998	Second Quarter 1998	Third Quarter 1998	Fourth Quarter 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.

New England Power Company
25 Research Drive
Westborough, Massachusetts 01582

Directors
(As of June 20, 2000)

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

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

Robert G. Powderly
Vice President of National Grid USA

Terry L. Schwennesen
Vice President of the Company

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 June 20, 2000)

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

Marc F. Mahoney
Vice President of the Company and of certain affiliates

John F. Malley
Vice President of the Company

James S. Robinson
Vice President of the Company

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

Terry L. Schwennesen
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

Patricia C. Easterly
Assistant Treasurer of the Company and Treasurer of an affiliate

Nancy B. Kellogg
Assistant Treasurer of the Company and of certain affiliates

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

Transfer Agent, Dividend Paying Agent, and Registrar of Preferred Stock, Fleet National Bank, Boston, Massachusetts

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