North Atlantic

North Atlantic Energy Service Corporation
P.O. Box 300
Seabrook, NH 03874
(603) 474-9521

The Northeast Utilities System

December 27, 2000

Docket 50-443

NYN-00107

CR 97001187-03

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Seabrook Station
<u>Guarantees of Payments of Deferred Premiums</u>

Pursuant to 10CFR 140.21(e), North Atlantic Energy Service Corporation (North Atlantic), on behalf of the licensees named in Facility Operating License NPF-86, provides herewith, the Annual Reports for 1999. The Annual Reports provided below demonstrate the collective ability of the licensees to meet their obligation for payment of deferred premiums.

Annual Reports for 1999 (containing certified financial statements) are enclosed for the following:

- North Atlantic Energy Corporation
- Connecticut Light and Power
- The United Illuminating Company
- Massachusetts Municipal Wholesale Electric Company
- New England Power Company
- Commonwealth Energy System (for subsidiary Canal Electric Company)
- New Hampshire Electric Cooperative, Inc.
- Taunton Municipal Lighting Plant
- Hudson Light and Power Department
- Bay Corp Holdings, LTD. (for subsidiary Great Bay Power Corporation and Little Bay Power Corporation)

M004

In addition, the Agreement of Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, dated May 1, 1973 as amended, and specifically the provisions of Paragraph 10.1, as amended by the Eighteenth Amendment, dated March 14, 1986, is incorporated by reference.

The enclosed annual reports are submitted pursuant to 10 CFR 50.71 (b).

Should you have any questions regarding this matter, please contact Mr. James M. Peschel, Manager - Regulatory Programs, at (603) 773-7194.

Very truly yours,

NORTH ATLANTIC ENERGY SERVICE CORP.

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

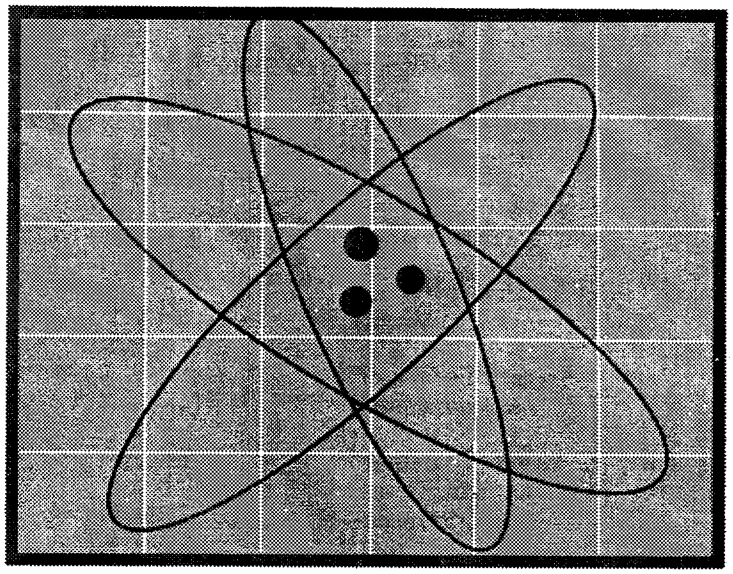
cc: (without enclosures)

H. J. Miller, NRC Region I Administrator
V. Nerses, NRC Project Manager, Project Directorate I-2
R. K. Lorson, NRC Senior Resident Inspector

cc: (with enclosures):

United States Nuclear Regulatory Commission
Attention: Director of Nuclear Reactor Regulation
Washington, DC 20555

ENCLOSURE TO NYN-00107



1999 Annual Report

North Atlantic

The Northeast Utilities System

Directors

William A. DiProfio
Seabrook Station
Manager

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

Bruce D. Kenyon
President and
Chief Executive Officer

Officers

Bruce D. Kenyon
President and
Chief Executive Officer

Ted C. Feigenbaum
Executive Vice President and
Chief Nuclear Officer

David R. McHale
Vice President and Treasurer

John J. Roman
Vice President and Controller

Marie A. Sullivan
Secretary

Robert A. Bersak
Assistant Secretary

Frederic Lee Klein
Assistant Treasurer

Robert C. Aronson
Assistant Treasurer—
Treasury Operations

March 1, 2000

1999 Annual Report

North Atlantic Energy Corporation

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North Atlantic Energy Corporation

Management's Discussion and Analysis of Financial Condition and Results of Operations

Financial Condition

Overview

North Atlantic Energy Corporation, (NAEC or the company), is a wholly owned operating subsidiary of Northeast Utilities (NU) and is part of the Northeast Utilities system (NU system). Public Service Company of New Hampshire (PSNH), is another wholly owned subsidiary of NU. PSNH is obligated to purchase the capacity and output from NAEC's 35.98 percent joint ownership interest in the Seabrook Station (Seabrook) nuclear unit under the terms of two life-of-unit, full cost recovery contracts (Seabrook Power Contracts).

The company's only assets are Seabrook and other Seabrook-related assets and its only source of revenues are the Seabrook Power Contracts. PSNH's obligations under the Seabrook Power Contracts are solely its own and have not been guaranteed by NU. The Seabrook Power Contracts contain no provisions entitling PSNH to terminate its obligations. If, however, PSNH were to fail to perform its obligations under the Seabrook Power Contracts, the company would be required to find other purchasers for Seabrook's power.

During 1999, NU made significant progress toward resolving restructuring issues in the state of New Hampshire by negotiating a global restructuring settlement that is still subject to regulatory approval. The "Agreement to Settle PSNH Restructuring" (Settlement Agreement), among other things, requires PSNH to sell its generation assets and certain power contracts, including PSNH's current purchased-power contract with NAEC for the output from Seabrook. If the Settlement Agreement is approved and implemented, NAEC and The Connecticut Light and Power Company (CL&P), another NU affiliate which has a 4.06 percent ownership interest in Seabrook, will sell their investments in Seabrook.

In 1999, NAEC's revenues increased to $287.4 million, up 3.9 percent from revenues of $276.7 million in 1998. In 1999, NAEC had net income of $29.6 million, compared to $29.5 million in 1998.

Mergers

In 1998 and 1999, NU management concluded that the pace of deregulation was accelerating throughout the northeastern United States and that shareholders would benefit from NU not only remaining a major provider of electric transmission and distribution service, but also becoming an unregulated marketer of both electricity and natural gas. NU management also concluded that as a result of the changes occurring in the highly competitive electric utility industry, increased size would be crucial to achieve its objective of being a leading provider of energy products and services in the Northeast.

On October 13, 1999, NU announced an agreement to merge with Consolidated Edison, Inc. (Con Edison), a financially stronger utility based in New York. The merger will create the nation's largest electric distribution system with more than 5 million customers and one of the 15 largest natural gas distribution systems with 1.4 million customers.

NU and Con Edison filed with various state and federal regulatory bodies in January 2000 to secure approval of the merger. The two companies expect these regulatory proceedings can be completed by the end of July 2000.

Also in 1999, NU management concluded that the NU system would be stronger and customers could be better served if NU reentered the natural gas distribution business that it had exited in 1989 and examined several potential businesses in New England. By adding gas to NU's energy mix, NU will be able to broaden its services to its existing customers and will have additional opportunities for long-term growth. In June 1999, NU announced an agreement to merge with Yankee Energy System, Inc. (Yankee). The merger will return to NU, Connecticut's largest natural gas distribution system, as well as several unregulated businesses involved in energy services, collections and other areas. The Yankee merger received Yankee shareholder approval in October 1999, final Connecticut Department of Public Utility Control approval in December 1999 and Securities and Exchange Commission (SEC) approval in January 2000. The merger closed on March 1, 2000.

Liquidity

During 1999, net cash flows provided by operations were $181.4 million, compared to $128.7 million in 1998 and $55.6 million in 1997. The increase in 1999 was primarily due to a decrease in tax payments.

Net cash flows used in financing activities were $130 million in 1999, compared to $75 million in 1998 and $37.6 million in 1997. This included $70 million to retire long-term debt, compared to $20 million paid in 1998 and 1997. Cash dividends on common shares paid in 1999 were $60 million, compared to $45 million in 1998 and $25 million in 1997.

Including investments made in the NU System Money Pool, construction expenditures and investments in nuclear decommissioning trusts, net cash flows used in investing activities were $51.5 million in 1999, compared to $53.7 million in 1998 and $18.4 million in 1997.

Restructuring

In August 1999, NU, PSNH and the state of New Hampshire signed the Settlement Agreement which, once approved and implemented, will resolve a number of pending regulatory and court proceedings related to PSNH. The Settlement Agreement is awaiting approval of the New Hampshire Public Utilities Commission and is subject to legislative approval for the issuance of rate reduction bonds (securitization).

Some of the key components of the agreement for PSNH include an after-tax write-off of $225 million of stranded costs by PSNH; the recovery of the remaining stranded costs; the securitization of $725 million of approved stranded costs; a reduction in rates of an average of 18.3 percent; the opening of the New Hampshire electricity market to competition; and the sale of generation assets and wholesale power entitlements with transition service being available to customers for three years.

Upon the approval and implementation of the Settlement Agreement, NAEC and PSNH will restructure the Seabrook Power Contracts to provide for the buydown of the value of the Seabrook asset to $100 million. NAEC will utilize the restructuring payments it receives from PSNH to significantly reduce its capitalization. Subsequent to the contract buydown, NAEC will continue to bill PSNH for recovery of the remaining Seabrook cost of $100 million. NAEC's return on equity will be lowered to 7 percent. The Settlement Agreement also requires NAEC to sell via public auction its share of Seabrook, with the sale to occur no later than December 31, 2003. Upon a successful sale of NAEC's share of Seabrook, the existing Seabrook Power Contracts with PSNH and NAEC will be terminated. For further information regarding commitments and contingencies related to restructuring, see Note 7A, "Commitments and Contingencies - Restructuring," to the financial statements.

Nuclear Generation

Seabrook

Seabrook achieved an annual capacity factor of 86.4 percent in 1999. However, since returning to service on May 13, 1999, after a 48-day refueling and maintenance outage, Seabrook has achieved a 99 percent capacity factor through December 31, 1999.

NAEC anticipates auctioning its 35.98 percent share of Seabrook, with the 4.06 percent owned by its affiliate, CL&P, after approval of the Settlement Agreement.

Nuclear Decommissioning

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear units in their financial statements.

Currently, the Financial Accounting Standards Board plans to review the accounting for obligations associated with the retirement of long-lived assets, including the decommissioning of nuclear units. If current accounting practices for nuclear decommissioning change, the annual provision for decommissioning could increase relative to 1999, and the estimated cost for decommissioning could be recorded as a liability with recognition of an increase in the cost of the related nuclear unit. However, management does not believe that such a change will have a material impact on NAEC's financial statements.

Spent Nuclear Fuel Disposal Costs

The United States Department of Energy (DOE) originally was scheduled to begin accepting delivery of spent fuel in 1998. However, delays in confirming the suitability of a permanent storage site continually have postponed plans for the DOE's long-term storage and disposal site. Extended delays or a default by the DOE could lead to consideration of costly alternatives. NAEC has the primary responsibility for the interim storage of its spent nuclear fuel. Seabrook is expected to have spent fuel storage capacity until at least 2010. Meeting spent fuel storage requirements beyond this period could require new and separate storage facilities. For further information regarding spent nuclear fuel disposal costs, see Note 7C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the financial statements.

Market Risk and Risk Management Instruments

NAEC uses swaps to manage its market risk exposures associated with changes in variable interest rates. NAEC uses these instruments to reduce risk by essentially creating offsetting market exposures. Based on the derivative instruments which are currently being utilized by NAEC to hedge some of its interest rate risks, there may be an impact on earnings upon adoption of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," which management has not estimated at this time.

Interest Rate Risk Management Instruments

NAEC holds variable-rate, long-term debt, exposing the company to interest rate risk. In order to hedge some of this risk, interest rate risk management instruments have been entered into on NAEC's $200 million variable-rate note. A 10 percent increase in market interest rates above the 1999 weighted average variable rate during 2000 would result in an immaterial impact on interest expense.

Other Matters

Environmental Matters

NAEC is subject to environmental laws and regulations structured to mitigate or remove the effect of past operations and to improve or maintain the quality of the environment. For further information regarding environmental matters, see Note 7B, "Commitments and Contingencies - Environmental Matters," to the financial statements.

Other Commitments and Contingencies

NAEC is subject to other commitments and contingencies primarily relating to nuclear insurance contingencies, its Seabrook construction program and the New England Power Pool generation pricing. For further information regarding these other commitments and contingencies, see Note 7, "Commitments and Contingencies," to the financial statements.

Year 2000 Issues

The transition into the year 2000 was a success for the NU system and NAEC. Its mission to provide safe, reliable energy to its customers and to ensure continued operability of critical business functions was not affected by any year 2000 related issues.

The projected total cost of the year 2000 program is estimated at $21 million. The total cost to date was funded through operating cash flows. The NU system has incurred and expensed $20 million related to year 2000 readiness efforts.

Forward Looking Statements

This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts. Words such as *estimates, expects, anticipates, intends, plans,* and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in historical weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments, and other presently unknown or unforeseen factors.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

Income Statement Variances
(Millions of Dollars)

	1999 over/(under) 1998		1998 over/(under) 1997	
	Amount	Percent	Amount	Percent
Operating Revenues	$11	4%	$ 84	44%
Operating Expenses:				
Fuel	2	17	-	-
Other operation and maintenance	10	19	(12)	(20)
Depreciation	2	9	-	-
Amortization of regulatory assets, net	-	-	79	(a)
Federal and state income taxes	(6)	(28)	11	(a)
Taxes other than income taxes	2	17	(1)	(8)
Operating Income	(4)	(8)	(3)	(5)
Deferred Seabrook return - other funds	(2)	(34)	-	-
Other, net	1	12	(8)	(a)
Interest charges, net	(1)	(3)	(1)	(2)
Net Income	-	-	-	-

(a) Percent greater than 100.

Operating Revenues

Operating revenues represent amounts billed to PSNH under the terms of the Seabrook Power Contracts and for decommissioning expense.

Operating revenues increased in 1999, primarily due to the higher operating expenses related to the Seabrook refueling and maintenance outage in 1999.

Operating revenues increased in 1998, primarily due to amounts billed to PSNH for the amortization of the Seabrook deferred return which began in December 1997.

Fuel

Fuel expense increased in 1999, primarily due to a higher fuel amortization rate since the Seabrook refueling outage.

Other Operation and Maintenance

Other operation and maintenance (O&M) expenses increased in 1999, primarily due to higher costs relating to the Seabrook refueling outage.

Other O&M expenses decreased in 1998, primarily due to lower costs associated with Seabrook outages in 1998.

Depreciation

Depreciation increased in 1999 due to shorter useful lives for 1999 plant asset additions.

Federal and State Income Taxes

Federal and state income taxes decreased in 1999, primarily due to lower taxable income.

Federal and state income taxes increased in 1998, primarily due to higher taxable income.

Taxes Other Than Income Taxes

Taxes other than income taxes increased in 1999, as the result of the New Hampshire change to a statewide utility property tax in place of the nuclear station tax.

The change in taxes other than income taxes in 1998 was not significant.

Deferred Seabrook Return - Other Funds

The deferred Seabrook return income decreased in 1999 as NAEC continues to recover the Seabrook deferred return, reducing the outstanding balance.

Other, Net

Other, net increased in 1999, primarily due to higher interest income on investments in the NU System Money Pool.

Other, net decreased in 1998, primarily due to the amortization of the taxes associated with the Seabrook phase-in costs, which began in December 1997.

Interest Charges, Net

Interest charges, net decreased in 1999 and 1998, primarily due to lower long-term debt outstanding.

North Atlantic Energy Corporation

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors
of North Atlantic Energy Corporation:

We have audited the accompanying balance sheets of North Atlantic Energy Corporation (a New Hampshire corporation and a wholly owned subsidiary of Northeast Utilities) as of December 31, 1999 and 1998, and the related statements of income, common stockholder's equity and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of North Atlantic Energy Corporation as of December 31, 1999 and 1998, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999, in conformity with generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the company will continue as a going concern. As discussed in Note 7A, Public Service Company of New Hampshire (PSNH), Northeast Utilities, and the state of New Hampshire are involved in litigation regarding the proposed implementation of restructuring legislation. PSNH is the sole customer of the company. The restructuring legislation as currently contemplated would require the company to discontinue the application of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation." The discontinuance would result in the company being in technical default under its current financial covenants, which would, if not waived or renegotiated, give rise to the rights of lenders to accelerate the payment of approximately $405 million of the company's indebtedness and approximately $516 million of PSNH's indebtedness. Although a settlement agreement on restructuring has been reached among the company, the state of New Hampshire, and others, implementation is subject to significant contingencies, including New Hampshire legislative, federal and state regulatory, and financial

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

lender approvals. These conditions raise substantial doubt about the company's ability to continue as a going concern. The financial statements referred to above do not include any adjustments that might result from the outcome of this uncertainty.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
January 25, 2000

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NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF INCOME

FOR THE YEAR ENDED DECEMBER 31,	1999	1998	1997
	(Thousands of Dollars)		
Operating Revenues	$ 287,369	$ 276,685	$ 192,381
Operating Expenses:			
Operation -			
Fuel	15,596	13,305	13,405
Other	41,727	36,763	39,091
Maintenance	19,030	14,120	24,146
Depreciation	27,576	25,381	25,170
Amortization of regulatory assets, net	85,488	85,464	6,270
Federal and state income taxes	34,854	36,194	14,845
Taxes other than income taxes	13,370	11,401	12,393
Total operating expenses	237,641	222,628	135,320
Operating Income	49,728	54,057	57,061
Other Income:			
Deferred Seabrook return - other funds	4,417	6,731	7,205
Other, net	(7,432)	(8,435)	(747)
Income taxes	19,131	14,378	4,394
Other income, net	16,116	12,674	10,852
Income before interest charges	65,844	66,731	67,913
Interest Charges:			
Interest on long-term debt	45,297	50,082	50,722
Other interest	(542)	(676)	649
Deferred Seabrook return - borrowed funds	(8,467)	(12,169)	(13,411)
Interest charges, net	36,288	37,237	37,960
Net Income	$ 29,556	$ 29,494	$ 29,953

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

NORTH ATLANTIC ENERGY CORPORATION

BALANCE SHEETS

AT DECEMBER 31,	1999	1998
	(Thousands of Dollars)	
ASSETS		
Utility Plant, at original cost:		
Electric	$ 736,472	$ 753,379
Less: Accumulated provision for depreciation	196,694	165,114
	539,778	588,265
Construction work in progress	10,274	7,090
Nuclear fuel, net	21,149	23,644
Total net utility plant	571,201	618,999
Other Property and Investments:		
Nuclear decommissioning trusts, at market	43,667	35,210
	43,667	35,210
Current Assets:		
Cash	-	71
Special deposits	7	11,198
Notes receivable from affiliated companies	56,400	30,350
Accounts receivable from affiliated companies	22,840	23,804
Taxes receivable	11,717	7,887
Materials and supplies, at average cost	13,088	12,812
Prepayments and other	1,766	2,198
	105,818	88,320
Deferred Charges:		
Regulatory assets	129,641	199,882
Unamortized debt expense	1,780	2,742
	131,421	202,624
Total Assets	$ 852,107	$ 945,153

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

NORTH ATLANTIC ENERGY CORPORATION

BALANCE SHEETS

AT DECEMBER 31,	1999	1998
	(Thousands of Dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par value - 1,000 shares authorized and outstanding in 1999 and 1998............	$ 1	$ 1
Capital surplus, paid in.............................	160,999	160,999
Retained earnings....................................	12,752	43,196
Total common stockholder's equity..............	173,752	204,196
Long-term debt.......................................	135,000	405,000
Total capitalization..........................	308,752	609,196
Current Liabilities:		
Long-term debt - current portion.......................	270,000	70,000
Accounts payable.......................................	11,694	5,924
Accounts payable to affiliated companies...............	806	867
Accrued taxes..	-	710
Accrued interest.......................................	2,340	2,987
Other..	272	285
	285,112	80,773
Deferred Credits and Other Long-term Liabilities:		
Accumulated deferred income taxes......................	222,601	209,634
Deferred obligation to affiliated company..............	12,984	22,728
Other..	22,658	22,822
	258,243	255,184
Total Capitalization and Liabilities..........	$ 852,107	$ 945,153

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

NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock	Capital Surplus, Paid In	Retained Earnings (a)	Total
		(Thousands of Dollars)		
Balance at January 1, 1997	$ 1	$ 160,999	$ 53,749	$ 214,749
Net income for 1997.................			29,953	29,953
Cash dividends on common stock......			(25,000)	(25,000)
Balance at December 31, 1997............	1	160,999	58,702	219,702
Net income for 1998.................			29,494	29,494
Cash dividends on common stock......			(45,000)	(45,000)
Balance at December 31, 1998............	1	160,999	43,196	204,196
Net income for 1999.................			29,556	29,556
Cash dividends on common stock......			(60,000)	(60,000)
Balance at December 31, 1999............	$ 1	$ 160,999	$ 12,752	$ 173,752

(a) All retained earnings are available for distribution, plus an allowance of $10 million.

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

NORTH ATLANTIC ENERGY CORPORATION

STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	1999	1998	1997
	For the Years Ended December 31,		
Operating Activities:			
Net income	$ 29,556	$ 29,494	$ 29,953
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation	27,576	25,381	25,170
Amortization of nuclear fuel	12,642	10,453	10,705
Deferred income taxes and investment tax credits, net	452	6,010	22,649
Deferred return - Seabrook	(12,884)	(18,900)	(20,616)
Amortization of regulatory assets, net	85,488	85,464	6,270
Deferred obligation to affiliated company	(9,744)	(9,744)	(812)
Other sources of cash	35,486	18,214	3,370
Changes in working capital:			
Receivables	964	1,891	(9,273)
Materials and supplies	(276)	191	90
Accounts payable	5,709	(7,161)	(11,835)
Accrued taxes	(710)	710	(3,486)
Other working capital (excludes cash)	7,133	(13,258)	3,429
Net cash flows provided by operating activities	181,392	128,745	55,614
Financing Activities:			
Net (decrease)/increase in short-term debt	-	(9,950)	7,450
Reacquisitions and retirements of long-term debt	(70,000)	(20,000)	(20,000)
Cash dividends on common stock	(60,000)	(45,000)	(25,000)
Net cash flows used in financing activities	(130,000)	(74,950)	(37,550)
Investing Activities:			
Investment in plant:			
Electric utility plant	(7,895)	(9,028)	(6,606)
Nuclear fuel	(9,934)	(6,474)	(6,147)
Net cash flows used for investments in plant	(17,829)	(15,502)	(12,753)
Investment in NU system Money Pool	(26,050)	(30,350)	-
Investment in nuclear decommissioning trusts	(7,584)	(7,885)	(5,597)
Net cash flows used in investing activities	(51,463)	(53,737)	(18,350)
Net (decrease)/increase in cash for the period	(71)	58	(286)
Cash - beginning of period	71	13	299
Cash - end of period	$ -	$ 71	$ 13
Supplemental Cash Flow Information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 38,042	$ 42,498	$ 45,297
Income taxes	$ 3,000	$ 22,136	$ -

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About North Atlantic Energy Corporation

North Atlantic Energy Corporation (NAEC or the company) along with The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), and Holyoke Water Power Company (HWP) are the operating companies comprising the Northeast Utilities system (NU system) and are wholly owned by Northeast Utilities (NU). The NU system serves in excess of 30 percent of New England's electric needs and is one of the 20 largest electric utility systems in the country as measured by revenues. The NU system furnishes franchised retail electric service in New Hampshire, Connecticut and western Massachusetts through PSNH, CL&P and WMECO. NAEC owns 35.98 percent of the Seabrook Station (Seabrook) nuclear unit and sells all of its entitlement to the capacity and output of Seabrook to PSNH under the terms of two life-of-unit, full cost recovery contracts (Seabrook Power Contracts). HWP, also is engaged in the production and distribution of electric power.

NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) and the NU system, including NAEC, is subject to provisions of the 1935 Act. Arrangements among the NU system companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the Federal Energy Regulatory Commission (FERC) and/or the SEC. NAEC is subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions.

Several wholly owned subsidiaries of NU provide support services for the NU system companies and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting administrative, information resources, engineering, financial, legal, operational, planning, purchasing, and other services to the NU system companies. Northeast Nuclear Energy Company acts as agent for the NU system companies and other New England utilities in operating the Millstone nuclear units. North Atlantic Energy Service Corporation (NAESCO) has operational responsibility for Seabrook.

On October 13, 1999, NU and Consolidated Edison, Inc. (Con Edison) announced that they have agreed to a merger to combine the two companies. For further information, see Note 11, "Merger Agreement with Con Edison."

B. Presentation

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

Certain reclassifications of prior years' data have been made to conform with the current year's presentation.

All transactions among affiliated companies are on a recovery of cost basis which may include amounts representing a return on equity and are subject to approval by various federal and state regulatory agencies.

C. New Accounting Standards

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 establishes accounting and reporting standards for derivative instruments and hedging activities. This statement will require derivative instruments utilized by NAEC to be recognized as assets or liabilities at fair value.

In June 1999, the FASB delayed the adoption date of SFAS No. 133 until January 1, 2001.

Based on the derivative instruments which currently are being utilized by NAEC to hedge some of its interest rate risk there may be an impact on earnings upon adoption of SFAS No. 133 which management has not estimated at this time.

D. Jointly Owned Electric Utility Plant

Seabrook: NAEC has a 35.98 percent ownership interest in Seabrook, a 1,148 megawatt nuclear generating unit. NAEC sells all of its share of the power generated by Seabrook to PSNH under the Seabrook Power Contracts. NAEC expects to auction its investment in Seabrook upon the resolution of the restructuring issues in the state of New Hampshire.

NAEC's share of Seabrook's plant-in-service as of December 31, 1999 and 1998, was $728 million and $721.2 million, respectively, and the accumulated provision for depreciation was $153 million and $130.7 million, respectively.

E. Depreciation

The provision for depreciation is calculated using the straight-line method based on estimated remaining lives of depreciable utility plant-in-service, adjusted for salvage value and removal costs, as approved by the appropriate

regulatory agency. Except for major facilities, depreciation rates are applied to the average plant-in-service during the period. Major facilities are depreciated from the time they are placed in service. When plant is retired from service, the original cost of plant, including costs of removal, less salvage, is charged to the accumulated provision for depreciation. The costs of closure and removal of nonnuclear facilities are accrued over the life of the plant as a component of depreciation. The depreciation rates for the several classes of electric plant-in-service are equivalent to a composite rate of 3.8 percent in 1999 and 3.5 percent in 1998 and 1997.

F. Seabrook Power Contracts

NAEC and PSNH have entered into two power contracts that obligate PSNH to purchase NAEC's share of the capacity and output of Seabrook for the term of Seabrook's operating license. Under the terms of the power contracts, PSNH is obligated to pay NAEC's cost of service during this period, regardless of whether Seabrook is operating. NAEC's cost of service includes all of its Seabrook-related costs, including operation and maintenance expenses, fuel expense, income and property tax expense, depreciation expense, certain overhead and other costs, and a return on its allowed investment.

The Seabrook Power Contracts established the value of the initial investment in Seabrook at $700 million. As prescribed by the 1989 rate agreement between NU, PSNH, and the state of New Hampshire (Rate Agreement), as of May 1, 1996, NAEC phased into rates 100 percent of the recoverable portion of its investment in Seabrook. From June 5, 1992 (the date NU acquired PSNH and NAEC acquired Seabrook from PSNH - the Acquisition Date) through November 1997, NAEC recorded a $203.9 million deferred return on its investment in Seabrook. At November 30, 1997, NAEC's utility plant included $84.1 million of the deferred return that was transferred as part of the Seabrook plant assets to NAEC on the Acquisition Date.

Beginning on December 1, 1997, the deferred return, including the portion transferred to NAEC, began to be billed through the Seabrook Power Contracts to PSNH. The deferred return will be fully recovered from customers by May 2001. NAEC is depreciating its initial investment over the term of Seabrook's operating license (39 years), and any subsequent plant additions are depreciated on a straight-line basis over the remaining term of the Seabrook Power Contracts at the time the subsequent additions are placed in service.

Under the current Seabrook Power Contracts, if Seabrook is shut down prior to the expiration of its operating license, PSNH will be unconditionally required to pay NAEC termination costs for 39 years, less the period during which Seabrook has operated. These termination costs will reimburse NAEC for its share of Seabrook shut-down and decommissioning costs and will pay NAEC a return of and on any undepreciated balance of its initial investment over the remaining term of the Seabrook Power Contracts. In addition, PSNH will pay NAEC a return of and on any capital additions to the plant made after the Acquisition Date over a period of five years after shut down (net of any tax benefits to NAEC attributable to the cancellation).

In August 1999, NU, PSNH and the state of New Hampshire signed the "Agreement to Settle PSNH Restructuring" (Settlement Agreement) which, once approved and implemented, will resolve a number of pending regulatory and court proceedings related to PSNH. The Settlement Agreement is awaiting approval of the New Hampshire Public Utilities Commission (NHPUC) and is subject to legislative approval for the issuance of rate reduction bonds (securitization). The Settlement Agreement also requires NAEC to sell via public auction its share of Seabrook, with the sale to occur no later than December 31, 2003. Upon the approval and implementation of the Settlement Agreement, NAEC and PSNH will restructure the power contracts to provide for the buydown of the value of the Seabrook asset to $100 million. Upon a successful sale of NAEC's share of Seabrook, the existing Seabrook Power Contracts between NAEC and PSNH will be terminated. However, PSNH will continue to be responsible for funding NAEC's ownership share of Seabrook's decommissioning liability.

G. Regulatory Accounting and Assets

The accounting policies of NAEC and the accompanying financial statements conform to generally accepted accounting principles applicable to rate-regulated enterprises and reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Assuming a cost-of-service based regulatory structure, regulators may permit incurred costs, normally treated as expenses, to be deferred and recovered through future revenues. Through their actions, regulators may also reduce or eliminate the value of an asset, or create a liability. If any portion of NAEC's operations were no longer subject to the provisions of SFAS No. 71, the company would be required to write off all of its related regulatory assets and liabilities unless there is a formal transition plan that provides for the recovery, through established rates, for the collection of these costs through a portion of the business, which would remain regulated on a cost-of-service basis. At the time of transition, NAEC would be required to determine

any impairment to the carrying costs of deregulated plant and inventory assets.

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management continues to believe it is probable that NAEC will recover its investments in long-lived assets, including regulatory assets. In addition, all material regulatory assets are earning a return. The components of NAEC's regulatory assets are as follows:

At December 31,	1999	1998
	(Millions of Dollars)	
Deferred costs-Seabrook	$ 88.5	$147.1
Income taxes, net	35.6	39.5
Recoverable energy costs	1.7	1.9
Unamortized loss on reacquired debt	3.8	11.4
	$129.6	$199.9

At this time, management continues to believe that the application of SFAS No. 71 remains appropriate. If the Settlement Agreement, as filed, is approved by the NHPUC and implemented, then NAEC will discontinue the application of SFAS No. 71. At that time, PSNH will make a payment to NAEC to buydown the Seabrook Power Contracts. NAEC will reduce the Seabrook asset to $100 million and will write off any remaining regulatory assets.

H. Income Taxes

The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions.

The tax effect of temporary differences, including timing differences accrued under previously approved accounting standards, which give rise to the accumulated deferred tax obligation is as follows:

At December 31,	1999	1998
	(Millions of Dollars)	
Accelerated depreciation and other plant-related differences	$205.1	$182.2
Regulatory assets - income tax gross up	12.2	13.6
Other	5.3	13.8
	$222.6	$209.6

I. **Recoverable Energy Costs**

Under the Energy Policy Act of 1992 (Energy Act), NAEC is assessed for its proportionate shares of the costs of decontaminating and decommissioning uranium enrichment plants owned by the United States Department of Energy (DOE) (D&D Assessment). The Energy Act requires that regulators treat D&D Assessments as a reasonable and necessary current cost of fuel, to be fully recovered in rates, like any other fuel cost. NAEC is currently recovering these costs through the Seabrook Power Contracts. As of December 31, 1999 and 1998, NAEC's total D&D Assessment deferral was $1.7 million and $1.9 million, respectively.

J. **Deferred Cost - Seabrook**

Under the Rate Agreement, the plant costs of Seabrook were phased into rates over a 7-year period beginning May 15, 1991. Total costs deferred under the phase-in plan were $288 million. Total deferred costs outstanding at December 31, 1999 and 1998 were $88.5 million and $147.1 million, respectively. This plan is accounted for in compliance with SFAS No. 92, "Regulated Enterprises - Accounting for Phase-In Plans." The costs will be fully recovered from PSNH's customers by May 2001.

K. **Interest Rate Risk Management Instruments**

NAEC utilizes market risk management instruments to hedge well-defined risks associated with variable interest rates. To qualify for hedge treatment, the underlying hedged item must expose the company to risks associated with market fluctuations and the market risk management instrument used must be designated as a hedge and must reduce the company's exposure to market fluctuations throughout the period. Amounts receivable or payable under interest rate management instruments are accrued and offset against interest expense.

2. NUCLEAR DECOMMISSIONING AND PLANT CLOSURE COSTS

Seabrook: Under the terms of the Rate Agreement, PSNH is obligated to pay NAEC's share of Seabrook's decommissioning costs, even if the unit is shut down prior to the expiration of its operating license. Accordingly, NAEC bills PSNH directly for its share of the costs of decommissioning Seabrook. Under New Hampshire law, Seabrook decommissioning funding requirements are set by the New Hampshire Nuclear Decommissioning Financing Committee (NDFC). During April 1999, the NDFC issued an order that adjusted the decommissioning collection period and funding levels assuming that Seabrook's anticipated energy producing life was 25 years from the date it went into commercial operation. Decommissioning collections are now expected to be completed by October 2015. The cost of funding decommissioning Seabrook is now being accrued over the estimated remaining accelerated funding period that was ordered by the NDFC.

Upon retirement, Seabrook must be decommissioned. Current decommissioning studies conclude that complete and immediate dismantlement as soon as practical after retirement continues to be the most viable and economic method of decommissioning a unit. These studies are reviewed and updated periodically to reflect changes in decommissioning requirements, costs, technology, and inflation. Changes in requirements or technology, the timing of funding or dismantling or adoption of a decommissioning method other than immediate dismantlement would change decommissioning cost estimates and the amounts required to be recovered.

The estimated cost of decommissioning NAEC's share of Seabrook, in year end 1999 dollars is $203.3 million. Nuclear decommissioning costs are accrued over the expected service life of the unit and are included in depreciation expense. Nuclear decommissioning expenses for the unit amounted to $6.8 million in 1999, $4.7 million in 1998 and $4.5 million in 1997. Nuclear decommissioning, as a cost of removal, is included in the accumulated provision for depreciation.

Payments for NAEC's ownership share of the cost of decommissioning Seabrook are paid to an independent decommissioning financing fund managed by the state of New Hampshire. Funding of the estimated decommissioning costs assumes escalated collections and after-tax earnings on the Seabrook decommissioning fund of 6.5 percent.

As of December 31, 1999 and 1998, NAEC has paid $32.7 million and $25.6 million (including payments made prior to the Acquisition Date by PSNH), into Seabrook's decommissioning financing fund. Earnings on the decommissioning financing fund increase the decommissioning trust balance and the accumulated reserve for depreciation. Unrealized gains and losses associated with the decommissioning financing fund also impact the balance of the trust and the accumulated reserve for depreciation. The fair values of the amounts in the external decommissioning trust for

NAEC were $43.7 million and $35.2 million at December 31, 1999 and 1998, respectively.

3. **SHORT-TERM DEBT**

Limits: The amount of short-term borrowings that may be incurred by NAEC is subject to periodic approval by either the SEC under the 1935 Act or by its state regulator. SEC authorization allowed NAEC, as of January 1, 1999, to incur short-term borrowings up to a maximum of $60 million.

Money Pool: Certain subsidiaries of NU, including NAEC, are members of the Northeast Utilities System Money Pool (Pool). The Pool provides a more efficient use of the cash resources of the NU system, and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU parent. NU parent may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on loans from NU parent, however, bear interest at NU parent's cost and must be repaid based upon the terms of NU parent's original borrowing. At December 31, 1999 and 1998, NAEC had no borrowings outstanding from the Pool.

4. **LONG-TERM DEBT**

Details of long-term debt outstanding are:

At December 31,	1999	1998
	(Millions of Dollars)	
First Mortgage Bonds:		
9.05% Series A, due 2002...........	$205	$275
Notes:		
Variable - Rate Facility, due 2000	200	200
Less amounts due within one year....	270	70
Long-term debt, net	$135	$405

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 1999, for the years 2000 through 2004 are $270 million, $70 million and $65 million for years 2000 through 2002, respectively, and no requirements for 2003 and 2004.

Essentially all utility plant of NAEC is subject to the liens of the company's first mortgage bond indenture.

Interest rate swaps effectively fix the interest rate of NAEC's $200 million variable-rate bank note at interest rates ranging from 5.81 percent to 6.07 percent.

5. INCOME TAX EXPENSE

The components of the federal and state income tax provisions were charged/(credited) to operations as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Current income taxes:			
Federal	$15.1	$15.2	$(11.9)
State	0.2	0.6	(0.3)
Total current	15.3	15.8	(12.2)
Deferred income taxes, net:			
Federal	0.4	4.0	21.5
State	-	2.0	1.1
Total deferred	0.4	6.0	22.6
Total income tax expense	$15.7	$21.8	$ 10.4

The components of total income tax expense/(credit) are classified as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Income taxes charged to operating expenses	$ 34.8	$ 36.2	$14.8
Other income taxes	(19.1)	(14.4)	(4.4)
Total income tax expense	$ 15.7	$ 21.8	$10.4

Deferred income taxes are comprised of the tax effects of temporary differences as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Depreciation	$ 19.5	$ 21.8	$20.8
Bond redemptions	(2.8)	(2.8)	(2.4)
Seabrook deferred return	(15.7)	(14.2)	3.4
Other	(0.6)	1.2	0.8
Deferred income taxes, net	$ 0.4	$ 6.0	$22.6

A reconciliation between income tax expense and the expected tax expense at 35 percent of pretax income is as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Expected federal income tax....	$15.8	$18.0	$14.1
Tax effect of differences:			
Amortization of regulatory assets	7.0	7.1	(0.3)
Depreciation.................	(3.2)	1.6	(0.5)
Deferred Seabrook return.....	(1.5)	(2.4)	(2.5)
State income taxes, net of federal benefit...........	0.1	1.7	0.5
Allocation of Parent Company's loss.............	(2.1)	(3.9)	(0.6)
Other, net...................	(0.4)	(0.3)	(0.3)
Total income tax expense.......	$15.7	$21.8	$10.4

6. DEFERRED OBLIGATION TO AFFILIATED COMPANY

At the time PSNH emerged from bankruptcy on May 16, 1991, in accordance with the phase-in under the Rate Agreement, it began to accrue a deferred return on the unphased-in portion of its Seabrook investment. From May 16, 1991 to the Acquisition Date, PSNH accrued a deferred return of $50.9 million. On the Acquisition Date, PSNH transferred the $50.9 million deferred return to NAEC as part of the Seabrook-related assets.

At the time PSNH transferred the deferred return to NAEC, it realized, for income tax purposes, a gain that was deferred under the consolidated income tax rules. Beginning December 1, 1997, the gain is being amortized into income for income tax purposes as the deferred return of $50.9 million, and the associated income taxes of $33.2 million, are collected by NAEC through the Seabrook Power Contracts scheduled to end in May 2001. As NAEC recovers the $33.2 million in years eight through ten of the Rate Agreement, corresponding payments are being made to PSNH. The balance of the deferred obligation to PSNH at December 31, 1999 and 1998, was $13 million and $22.7 million, respectively.

7. COMMITMENTS AND CONTINGENCIES

A. Restructuring

In August 1999, NU, PSNH and the state of New Hampshire signed a Settlement Agreement intended to settle a number of pending regulatory and court proceedings related to PSNH. Parties to the agreement included the governor of New Hampshire, the Governor's Office of Energy and Community Service, the New Hampshire attorney general, certain members of the staff of the NHPUC, PSNH, and NU. The Settlement Agreement was submitted to the NHPUC on August 2, 1999, and is awaiting

approval. If approved by the NHPUC, the Settlement Agreement would resolve 11 NHPUC dockets and PSNH's federal lawsuit which had enjoined the state of New Hampshire from implementing its restructuring legislation, would require PSNH to write off $225 million after-tax of its stranded costs and would allow for the recovery of the remaining amount. Also, implementation of the Settlement Agreement is contingent upon securitization. Securitization requires the initial approval of the NHPUC and final approval from the New Hampshire Legislature via enactment of appropriate legislation. Other approvals are also required from various federal and state regulatory agencies and financial lenders.

The Settlement Agreement also requires NAEC to auction its Seabrook investment. Once NAEC's share of Seabrook is sold, the existing Seabrook Power Contracts between NAEC and PSNH will be terminated. However, PSNH will continue to pay NAEC's ownership share of Seabrook's decommissioning liability.

B. Environmental Matters

The NU system, including NAESCO on behalf of NAEC, is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of our environment. As such, the NU system and NAESCO, have an active environmental auditing and training program and believes it is in compliance with the current laws and regulations.

However, the normal course of operations may necessarily involve activities and substances that expose NAEC to potential liabilities of which management cannot determine the outcome. Additionally, management cannot determine the outcome for liabilities that may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Management does not believe, however, that this will have a material impact on NAEC's financial statements.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, NAEC must pay the DOE for the disposal of spent nuclear fuel and high-level radioactive waste. The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. Fees for nuclear fuel burned are billed currently to customers and paid to the DOE on a quarterly basis.

D. Nuclear Insurance Contingencies

Insurance policies covering NAEC's ownership share of Seabrook have been purchased for the primary cost of repair, replacement or decontamination of utility property and certain extra costs for repair, replacement or decontamination or premature decommissioning of utility property.

NAEC is subject to retroactive assessments if losses under those policies exceed the accumulated funds available to the insurer. The maximum potential assessments against NAEC, including costs resulting from PSNH's contracts with NAEC, with respect to losses arising during the current policy year for the primary property insurance program and the excess property damage policies are $2.1 million and $3.2 million, respectively. In addition, insurance has been purchased by the NU system in the aggregate amount of $200 million on an industry basis for coverage of worker claims.

Under certain circumstances, in the event of a nuclear incident at one of the nuclear facilities covered by the federal government's third-party liability indemnification program, the NU system, including NAEC, could be assessed liabilities in proportion to its ownership interest in each of its nuclear units up to $83.9 million. The NU system's payment of this assessment would be limited to, in proportion to its ownership interest, $10 million in any one year per nuclear unit. In addition, if the sum of all claims and costs from any one nuclear incident exceeds the maximum amount of financial protection, the NU system would be subject to an additional 5 percent or $4.2 million liability, in proportion to its ownership interest in each of its nuclear units. Under the terms of the Seabrook Power Contracts with NAEC, PSNH could be obligated to pay for any assessment charged to NAEC as a cost of service. Based upon NAEC's ownership interest in Seabrook, PSNH's maximum liability, including any additional assessments, would be $31.3 million per incident, of which payments would be limited to $3.6 million per year.

E. Seabrook Construction Program

NAEC currently forecasts construction expenditures for its share of Seabrook to be $9.7 million for the years 2000-2001, including approximately $4.6 million for 2000. In addition, NAEC estimates that its share of Seabrook nuclear fuel requirements will be $46.3 million for the years 2000-2003, including $14.8 million for 2000.

F. **New England Power Pool (NEPOOL) Generation Pricing**

Disputes with respect to interpretation and implementation of the NEPOOL market rules have arisen with respect to various competitive product markets. In certain cases, NAEC stands to gain as a result of resolution of such disputes. In other cases, NAEC could incur additional costs as the result of resolution of the disputes. The various disputes are in various stages of resolution through alternative dispute resolution and regulatory review. It is too early to tell the level of potential gain or loss that may result upon resolution of these issues.

8. **MARKET RISK AND MANAGEMENT INSTRUMENTS**

Interest Rate Risk Management: NAEC uses swap instruments with financial institutions to hedge against interest rate risk associated with its $200 million variable-rate bank note. Under the agreements, NAEC exchanges quarterly payments based on a differential between a fixed contractual interest rate and the 3-month LIBOR rate at a given time. As of December 31, 1999 and 1998, NAEC had outstanding agreements with a total notional value of $200 million and mark-to-market positions of positive $0.5 million and negative $2.3 million, respectively.

Credit Risk: These agreements have been made with various financial institutions, each of which is rated "A3" or better by Moody's Investors Service rating group. NAEC is exposed to credit risk on its respective market risk management instruments if the counterparties fail to perform their obligations. Management anticipates that the counterparties will fully satisfy their obligations under the agreements.

9. **FAIR VALUE OF FINANCIAL INSTRUMENTS**

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Cash and cash equivalents: The carrying amounts approximate fair value due to the short-term nature of cash and cash equivalents.

Nuclear decommissioning trust: The investments held in NAEC's nuclear decommissioning fund were adjusted to market by $3.2 million as of December 31, 1999, and by $2.3 million as of December 31, 1998, with corresponding offsets to the accumulated provision for depreciation. The amounts adjusted in 1999 and 1998 represent cumulative gross unrealized holding gains. The cumulative gross unrealized holding losses were immaterial for 1999 and 1998.

Long-term debt: The fair value of NAEC's fixed-rate security is based upon the quoted market price for that issue or similar issue. The adjustable rate security is assumed to have a fair value equal to its carrying value.

The carrying amounts of NAEC's financial instruments and the estimated fair values are as follows:

	At December 31, 1999	
(Million of Dollars)	Carrying Amount	Fair Value
First mortgage bonds	$205.0	$207.8
Other long-term debt	$200.0	$200.0

	At December 31, 1998	
(Million of Dollars)	Carrying Amount	Fair Value
First mortgage bonds	$275.0	$284.5
Other long-term debt	$200.0	$200.0

10. SEGMENT INFORMATION

Effective January 1, 1999, the NU system companies, including NAEC, adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." The NU system is organized between regulated utilities and unregulated energy services. NAEC is included in the regulated utilities segment of the NU system and has no other reportable segments.

11. MERGER AGREEMENT WITH CON EDISON

On October 13, 1999, NU and Con Edison announced that they have agreed to a merger to combine the two companies. The shareholders of NU will receive $25 per share in a combination of cash and Con Edison common stock.

NU shareholders also have the right to receive an additional $1 per share if a definitive agreement to sell its interests (other than that now held by PSNH) in Millstone 2 and 3 is entered into and recommended by the Utility Operations and Management Unit of the Connecticut Department of Public Utility Control on or prior to the later of December 31, 2000, or the closing of the merger. Further, the value of the amount of cash or common stock to be received by NU shareholders is subject to increase by an amount of $0.0034 per share per day for each day that the transaction does not close after August 5, 2000.

Upon completion of the merger, NU will become a wholly owned subsidiary of Con Edison. The purchase is subject to the approval of the shareholders of both companies and several regulatory agencies. The companies anticipate that these regulatory procedures will be completed by July 2000.

North Atlantic Energy Corporation

SELECTED FINANCIAL DATA	1999	1998	1997	1996	1995
			(Thousands of Dollars)		
Operating Revenues	$287,369	$276,685	$ 192,381	$ 162,152	$ 157,183
Operating Income	49,728	54,057	57,061	54,889	51,394
Net Income	29,556	29,494	29,953	32,072	24,441
Cash Dividends on Common Stock	60,000	45,000	25,000	38,000	24,000
Total Assets	852,107	945,153	1,014,639	1,017,388	1,014,649
Long-Term Debt (a)	405,000	475,000	495,000	515,000	560,000

QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
1999	March 31	June 30	September 30	December 31
		(Thousands of Dollars)		
Operating Revenues	$70,289	$77,203	$69,779	$70,098
Operating Income	$12,475	$12,303	$12,122	$12,828
Net Income	$ 6,461	$ 6,243	$ 6,442	$10,410
1998				
Operating Revenues	$68,169	$69,627	$69,087	$69,802
Operating Income	$13,648	$13,365	$13,159	$13,885
Net Income	$ 6,909	$ 8,303	$ 7,170	$ 7,112

STATISTICS (Unaudited)	1999	1998	1997	1996	1995
Gross Electric Utility Plant at December 31, (Thousands of Dollars)	$767,895	$784,113	$811,140	$816,446	$806,892
kWh Sales (Millions) for the year ended December 31, ..	$ 3,125	$ 3,018	$ 2,859	$ 3,542	$ 3,016

(a) Includes portion due within one year.

North Atlantic Energy Corporation

First Mortgage Bonds

Trustee and Interest Paying Agent
United States Trust Company of New York
114 West 47th Street
New York, New York 10036

Address General Correspondence in Care of:
Northeast Utilities Service Company
Investor Relations Department
P.O. Box 270
Hartford, Connecticut 06141-0270
Telephone: (860) 665-5000

Data contained in this Annual Report are submitted for the sole purpose of providing information to present security holders about the Company.

General Offices
1000 Elm Street
P.O. Box 330
Manchester, New Hampshire 03105-0330

THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)			
Item 1: [X] An Initial (Original) Submission	OR	[ ] Resubmission No. ____	
Item 2: [ ] An Original Signed Form	OR	[X] Conformed Copy	

Form Approved
OMB No. 1902-0021
(Expires 11/30/2001)

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
CANAL ELECTRIC COMPANY	Dec. 31, 1999

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
One Post Office Square
Boston MA 02109
Telephone (617) 478 5000
Facsimile (617) 478 5900

REPORT OF INDEPENDENT ACCOUNTANTS

Canal Electric Company
Boston, Massachusetts

We have audited the balance sheet of Canal Electric Company as of December 31, 1999, and the related statements of income and retained earnings and of cash flows for the year then ended, included on Pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form No. 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As discussed in the notes to financial statements on Page 123, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Canal Electric Company as of December 31, 1999, and the results of its operations and its cash flows for the year ended December 31, 1999, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

The report is intended solely for the information and use of the Board of Directors and management of Canal Electric Company and the Federal Energy Regulatory Commission and should not be used for any other purpose.

PricewaterhouseCoopers LLP

January 26, 2000

NSTAR
800 Boylston Street
Boston, Massachusetts 02199

Canal Electric Company

April 28, 2000

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1A-21
Washington, DC 20426

In accordance with 18 C.F.R. section 385.2011 (c)(5), I hereby state that the paper copies contain the same information as contained in the electronic filing, that I know the contents of the paper copies and electronic filing, and that the contents as stated in the copies and in the electronic filing are true to the best of my knowledge and belief.

Sincerely,

RJWeafer Jr

Robert J. Weafer, Jr.
Vice President, Controller & CAO

INSTRUCTIONS FOR FILING THE
FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, Licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101), must submit this form.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) One million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus Losses)

III. What and Where to Submit

(a) Submit this form on electronic media consisting of two (2) duplicate data diskettes and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as contained on the electronic media, that the signer knows the contents of the paper copies and electronic media, and that the contents as stated in the copies and on the electronic media are true to the-best knowledge and belief of the signer.

(b) Submit, immediately upon publication, four (4) copies of the Latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21 Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a Letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below Listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent Licensed public accountant certified or Licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 41.'10-41.12 for specific qualifications).

III. What and Where to Submit (Continued)

(c) Continued

Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

When accompanying this form, insert the Letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the office of the Secretary at the address indicated at III (a).

Use the following form for the Letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statements of for the year ended on which we have reported separately under date of We have also reviewed schedules of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE. Room 2A-1 ED-12.2
Washington, DC 20426
(202) 208-2474

IV. When to Submit

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for this collection of information is estimated to average 1,217 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 (Attention: Mr. Michael Hitter, ED-12.3); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U.S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required). The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current year's amounts.

III Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, two (2) new data diskettes and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a) must be filed. Resubmissions must be numbered sequentially both on the diskettes and on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

VIII. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

Definitions

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

Federal Power Act, 16 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit: ...(3) "Corporation" means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shalt not include 'municipalities, as hereinafter defined;

(4) "Person" means an individual or a corporation;

(5) "Licensee" means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) "Municipality" means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry an the business of developing, transmitting, unitizing, or distributing power;..."

(11) "Project" means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered:

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission my prescribe the manner and form in which such reports shalt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed..."

General Penalties

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act ... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing..."

FERC FORM NO. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION		
01 Exact Legal Name of Respondent CANAL ELECTRIC COMPANY		02 Year of Report Dec. 31, 1999
03 Previous Name and Date of Change *(if name changed during year)* / /		
04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)* 800 Boylston Street, Boston, Massachusetts 02199		
05 Name of Contact Person Michael Farrell		06 Title of Contact Person Asst. Controller&Dir., Acct.
07 Address of Contact Person *(Street, City, State, Zip Code)* 26 Dartmouth Street, Westwood, Massachusetts 02090		
08 Telephone of Contact Person, *Including Area Code* (781) 441-8803	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/1999

ATTESTATION		
The undersigned officer certifies that he/she has examined the accompanying report: that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.		
01 Name Robert J. Weafer, Jr.	03 Signature RJWeafer Jr.	04 Date Signed *(Mo, Da, Yr)* 04/28/00
02 Title VP, Ctrl., Chief Acct. Officer		
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec 31, 1999

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During Year	424-425	None
68	Substations	426-427	None
69	Electric Distribution Meters and Line Transformers	429	None
70	Environmental Protection Facilities	430	
71	Environmental Protection Expenses	431	
72	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[ ] Four copies will be submitted

[X] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Robert J. Weafer, Jr., Vice President, Controller and Chief Accounting Officer
800 Boylston Street, Boston, MA 02199
26 Dartmouth Street, Westwood, MA 02090

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Massachusetts, April 17, 1902

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric Sales For Resale - Massachusetts

5. Have you engaged as the principle accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [X] Yes...Enter the date when such independent accountant was initially engaged: 10/28/1999
(2) [ ] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Direct control is exercised by NSTAR by virtue of its ownership of 100% of the common stock of the respondent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board and Chief Executive Officer	Thomas J. May	
2			
3	President and Chief Operating Officer	Russell D. Wright	
4			
5	Sr. Vice President - Strategy, Law & Policy	Douglas S. Horan	
6			
7	Sr. Vice President, Treasurer & Chief Financial Officer	James J. Judge	
8			
9	Sr. Vice President - Human Resources	Alison Alden	
10			
11	Sr. Vice President - Corporate Relations	L. Carl Gustin	
12			
13	Executive Vice President-Electrical Operations	Ronald A. Ledgett	
14			
15	Executive Vice President-Cust. Care/Shared Services	Deborah A. McLaughlin	
16			
17	Vice President / Clerk & General Counsel	Michael P. Sullivan	
18			
19	Vice President / Treasurer	James D. Rappoli (1)	
20			
21	Vice President/Controller & Chief Accounting Officer	Robert J. Weafer, Jr.	
22			
23	Vice President - Asset Management	Ellen K. Angley	
24			
25	Vice President - Network Services	Kevin F. Roberts	
26			
27	Vice President - Customer Services Delivery	Fred J. Greenberg	
28			
29	Vice President - Customer Care	Charles W. Kiely	
30			
31	Assistant Clerk	Theodora S. Convisser (2)	
32			
33	Assistant Clerk	Richard J. Morrison	
34			
35			
36	The merger of BEC Energy and Commonwealth		
37	Energy System resulted in significant changes		
38	in officers effective 9/20/99. Salary for the year		
39	represents the total salary and does not reflect salary		
40	allocated to affiliated companies.		
41			
42	(1) Resigned as of February 29, 2000		
43	(2) Resigned as of March 31, 2000		
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Thomas J. May (Chairman of the Board/Chief Executive	800 Boylston Street, Boston, MA 02199
2	--Officer	
3		
4	Russell D. Wright (President/Chief Operating Officer)	800 Boylston Street, Boston, MA 02199
5		
6	James J. Judge (Sr. Vice President, Treasurer & Chief	800 Boylston Street, Boston, MA 02199
7	--Financial Officer)	
8		
9	The merger of BEC Energy and Commonwealth	
10	Energy System resulted in significant changes	
11	in directors effective 9/20/99.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust(whether voting trust, etc.) duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a List of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights give other important particulars (details) concerning voting rights of such security. State whether voting right are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method explain briefly in a footnote.
4. Furnish particulars (details) concerning any options warrants, or rights outstanding at the end of the year others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or right the amount of such securities or assets so entitled to purchased by any officer, director, associated company, or of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the public where the options, warrants, or rights were issued prorata basis.

1. Give the date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors of the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting
	Total: 1,523,200 By Proxy: 1,523,200	January 22, 1999 One Main Street Cambridge, MA 02142-9150

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of Votes as of (date): / / Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	1,523,200	1,523,200		
5	TOTAL number of security holders	1	1		
6	TOTAL votes of security holders listed below	1,523,200	1,523,200		
7					
8	NSTAR				
9	800 Boylston Street				
10	Boston, MA 02199				
11					
12					
13					
14					
15					
16					
17					
18					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	None				
20					
21					
22					
23					
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25					
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27					
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30					
31					
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Name of Respondent	This Report Is:	Date of Report	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	12/31/1999	Dec 31, 1999

IMPORTANT CHANGES DURING THE YEAR (Continued)

1. None
2. On August 25, 1999 the Parent, Commonwealth Energy System, merged with BEC Energy. NSTAR became the new name of the parent company. The SEC approved the merger on May 12, 1999 in file numbers 1-4768 and 1-7316. The FERC approved the merger on July 1, 1999 in docket number EC 99-33000.
3. None
4. None
5. None
6. None
7. None
8. None
9. None
10. None
11. None
12. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	243,590,240	243,044,528
3	Construction Work in Progress (107)	200-201	1,851,865	2,550,595
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		245,442,105	245,595,123
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	56,624,360	58,054,381
6	Net Utility Plant (Enter Total of line 4 less 5)		188,817,745	187,540,742
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	23,581,001	23,887,726
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	20,456,737	21,584,324
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		3,124,264	2,303,402
10	Net Utility Plant (Enter Total of lines 6 and 9)		191,942,009	189,844,144
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	8,994	8,994
15	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	2,800,117	2,833,479
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		1,080,746	1,120,889
21	Special Funds (125-128)		2,985,822	3,828,663
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		6,875,679	7,792,025
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)		5,716	40,229
25	Special Deposits (132-134)		0	0
26	Working Fund (135)		13,120	12,088
27	Temporary Cash Investments (136)		258,925,000	0
28	Notes Receivable (141)		0	0
29	Customer Accounts Receivable (142)		6,498,122	0
30	Other Accounts Receivable (143)		3,237,821	94,553
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		0	0
32	Notes Receivable from Associated Companies (145)		0	0
33	Accounts Receivable from Assoc. Companies (146)		55,877,272	9,090,619
34	Fuel Stock (151)	227	0	0
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	1,266,731	1,307,916
38	Merchandise (155)	227	0	0
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	898	3,518
44	Gas Stored Underground - Current (164.1)		0	0
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		884,447	954,081
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		0	0
49	Rents Receivable (172)		0	0
50	Accrued Utility Revenues (173)		659,000	0
51	Miscellaneous Current and Accrued Assets (174)		0	0
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		327,368,127	11,503,004

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)		0	0
55	Extraordinary Property Losses (182.1)	230	0	0
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230	850,406	853,236
57	Other Regulatory Assets (182.3)	232	17,941,832	18,099,456
58	Prelim. Survey and Investigation Charges (Electric) (183)		282,530	1,081
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
60	Clearing Accounts (184)		0	0
61	Temporary Facilities (185)		0	0
62	Miscellaneous Deferred Debits (186)	233	1,872,819	2,086,967
63	Def. Losses from Disposition of Utility Plt. (187)		0	0
64	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
65	Unamortized Loss on Reaquired Debt (189)		357,610	0
66	Accumulated Deferred Income Taxes (190)	234	3,348,919	995,953
67	Unrecovered Purchased Gas Costs (191)		0	0
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		24,654,116	22,036,693
69	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,52,68)		550,839,931	231,175,866

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	38,080,000	38,080,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	8,320,729	8,320,729
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	12,019	12,019
11	Retained Earnings (215, 215.1, 216)	118-119	242,271,126	24,429,454
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-305,974	-272,615
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		288,353,862	70,545,549
15	**LONG-TERM DEBT**			
16	Bonds (221)	256-257	0	0
17	(Less) Reaquired Bonds (222)	256-257	0	0
18	Advances from Associated Companies (223)	256-257	0	0
19	Other Long-Term Debt (224)	256-257	0	0
20	Unamortized Premium on Long-Term Debt (225)		4,894	0
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		36,528	0
22	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		-31,634	0
23	**OTHER NONCURRENT LIABILITIES**			
24	Obligations Under Capital Leases - Noncurrent (227)		10,551,216	9,987,696
25	Accumulated Provision for Property Insurance (228.1)		0	0
26	Accumulated Provision for Injuries and Damages (228.2)		0	0
27	Accumulated Provision for Pensions and Benefits (228.3)		0	0
28	Accumulated Miscellaneous Operating Provisions (228.4)		180,329	0
29	Accumulated Provision for Rate Refunds (229)		0	0
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		10,731,545	9,987,696
31	**CURRENT AND ACCRUED LIABILITIES**			
32	Notes Payable (231)		0	48,575,000
33	Accounts Payable (232)		30,665,620	8,420,972
34	Notes Payable to Associated Companies (233)		0	0
35	Accounts Payable to Associated Companies (234)		8,677,511	585,359
36	Customer Deposits (235)		0	0
37	Taxes Accrued (236)	262-263	121,192,154	14,996,269
38	Interest Accrued (237)		0	21,137
39	Dividends Declared (238)		0	0
40	Matured Long-Term Debt (239)		0	0
41	Matured Interest (240)		0	0
42	Tax Collections Payable (241)		661,704	2,218
43	Miscellaneous Current and Accrued Liabilities (242)		3,309,283	3,658,500
44	Obligations Under Capital Leases-Current (243)		567,759	563,519
45	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		165,074,031	76,822,974

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	**DEFERRED CREDITS**			
47	Customer Advances for Construction (252)		0	0
48	Accumulated Deferred Investment Tax Credits (255)	266-267	8,427,481	8,126,357
49	Deferred Gains from Disposition of Utility Plant (256)		0	0
50	Other Deferred Credits (253)	269	10,002,368	10,580,575
51	Other Regulatory Liabilities (254)	278	0	0
52	Unamortized Gain on Reaquired Debt (257)		0	0
53	Accumulated Deferred Income Taxes (281-283)	272-277	68,282,278	55,112,715
54	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		86,712,127	73,819,647
55			0	0
56			0	0
57			0	0
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		550,839,931	231,175,866

Name of Respondent	This Report Is:	Date of Report (Mo. Da. Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	47,342,396	181,997,857
3	Operating Expenses			
4	Operation Expenses (401)	320-323	10,480,467	115,367,386
5	Maintenance Expenses (402)	320-323	1,974,579	12,467,840
6	Depreciation Expense (403)	336-337	6,991,548	20,546,798
7	Amort. & Depl. of Utility Plant (404-405)	336-337		
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,319,436	1,319,436
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	1,257,562	3,238,566
14	Income Taxes - Federal (409.1)	262-263	17,934,613	109,267,653
15	- Other (409.1)	262-263	2,573,483	21,412,805
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	2,819,730	3,208,418
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	9,378,528	8,287,502
18	Investment Tax Credit Adj. - Net (411.4)	266	-301,124	-525,486
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			34,235
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		35,671,766	277,981,679
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		11,670,630	-95,983,822

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.
B. Enter on pages 122-123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.
10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages.122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
[redacted]						1
47,342,396	181,997,857					2
[redacted]						3
10,480,467	115,367,386					4
1,974,579	12,467,840					5
6,991,548	20,546,798					6
						7
1,319,436	1,319,436					8
						9
						10
						11
						12
1,257,562	3,238,566					13
17,934,613	109,267,653					14
2,573,483	21,412,805					15
2,819,730	3,208,418					16
9,378,528	8,287,502					17
-301,124	-525,486					18
						19
						20
	34,235					21
						22
35,671,766	277,981,679					23
11,670,630	-95,983,822					24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec 31, 1999

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		11,670,630	-95,983,822
26	Other Income and Deductions			
27	Other Income			
28	Nonutilty Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)			
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			
31	Revenues From Nonutility Operations (417)			
32	(Less) Expenses of Nonutility Operations (417.1)			
33	Nonoperating Rental Income (418)			2,260
34	Equity in Earnings of Subsidiary Companies (418.1)	119	627,117	454,021
35	Interest and Dividend Income (419)		1,579,792	42,370
36	Allowance for Other Funds Used During Construction (419.1)			
37	Miscellaneous Nonoperating Income (421)		257,586	600
38	Gain on Disposition of Property (421.1)		12,694,100	305,719,186
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		15,158,595	306,218,437
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)			
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	88,148	7,457,200
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		88,148	7,457,200
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263		1,006
47	Income Taxes-Federal (409.2)	262-263		
48	Income Taxes-Other (409.2)	262-263		
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277		66,854
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		2,661,439
51	Investment Tax Credit Adj.-Net (411.5)			-2,013,719
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)			-4,607,298
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		15,070,447	303,368,535
55	Interest Charges			
56	Interest on Long-Term Debt (427)			7,696,049
57	Amort. of Debt Disc. and Expense (428)		2,389,384	118,299
58	Amortization of Loss on Reaquired Debt (428.1)			40,106
59	(Less) Amort. of Premium on Debt-Credit (429)		283	635
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340	333,729	55,219
62	Other Interest Expense (431)	340	3,734,891	478,056
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		120,363	118,997
64	Net Interest Charges (Enter Total of lines 56 thru 63)		6,337,358	8,268,097
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		20,403,719	199,116,616
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		20,403,719	199,116,616

Name of Respondent	This Report Is:	Date of Report	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/1999	Dec. 31, 1999

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		242,271,126
2	Changes		
3	Adjustments to Retained Earnings (Account 439)		
4			
5			
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		
10			
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		
16	Balance Transferred from Income (Account 433 less Account 418.1)		19,776,602
17	Appropriations of Retained Earnings (Acct. 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		
23	Dividends Declared-Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		
30	Dividends Declared-Common Stock (Account 438)		
31			-238,212,030
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-238,212,030
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		593,756
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		24,429,454

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	APPROPRIATED RETAINED EARNINGS (Account 215)		
39			
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)		
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)		
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total 38, 47)		24,429,454
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
49	Balance-Beginning of Year (Debit or Credit)		-305,974
50	Equity in Earnings for Year (Credit) (Account 418.1)		627,117
51	(Less) Dividends Received (Debit)		593,758
52			
53	Balance-End of Year (Total lines 49 thru 52)		-272,615

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	20,403,719
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	6,582,000
5	Amortization of Seabrook Unit 1 Preconstruction Cost	1,319,436
6		
7		
8	Deferred Income Taxes (Net)	-6,558,801
9	Investment Tax Credit Adjustment (Net)	-301,124
10	Net (Increase) Decrease in Receivables	57,087,043
11	Net (Increase) Decrease in Inventory	-43,805
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	-136,511,548
14	Net (Increase) Decrease in Other Regulatory Assets	-157,624
15	Net Increase (Decrease) in Other Regulatory Liabilities	
16	(Less) Allowance for Other Funds Used During Construction	
17	(Less) Undistributed Earnings from Subsidiary Companies	627,117
18	Other: Dividends from Subsidiary Companies	593,758
19	Other	2,681,178
20		
21		
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	-55,532,885
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-720,778
27	Gross Additions to Nuclear Fuel	-306,726
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	
30	(Less) Allowance for Other Funds Used During Construction	
31	Other: Sale of Generating Assets	-12,694,100
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-13,721,604
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	258,925,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

STATEMENT OF CASH FLOWS

4. Investing Activities include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.

5. Codes used:

(a) Net proceeds or payments.

(b) Bonds, debentures and other long-term debt.

(c) Include commercial paper.

(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other	
54		
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	245,203,396
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	
62	Preferred Stock	
63	Common Stock	
64	Other:	
65		
66	Net Increase in Short-Term Debt (c)	48,575,000
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	48,575,000
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	
79		
80	Dividends on Preferred Stock	
81	Dividends on Common Stock	-238,212,030
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	-189,637,030
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	33,481
87		
88	Cash and Cash Equivalents at Beginning of Year	18,836
89		
90	Cash and Cash Equivalents at End of Year	52,317

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

The notes attached are a reprint of the notes to the financial statements included in Canal Electric Company's 1999 Annual Report to the SEC on Form 10-K. Therefore, certain amounts may differ from those that are presented on the basis of accounting prescribed by the FERC.

The financial statements are prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission and Department of Telecommunications and Energy as set forth in the applicable Uniform System of Accounts and published accounting releases. This is a comprehensive basis of accounting consistent with generally accepted accounting principles (GAAP).

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

(1) General Information

Canal Electric Company (the Company) is a wholly-owned subsidiary of Commonwealth Energy System that is a wholly-owned indirect subsidiary of NSTAR. NSTAR is the new holding company that was formed, effective August 25, 1999 upon completion of a merger transaction between Commonwealth Energy System (COM/Energy, formerly the parent of the Company) and BEC Energy (formerly the parent company of Boston Edison Company). The merger creates an energy delivery company that includes the Company, serving approximately 1.3 million customers located in Massachusetts including more than one million electric customers in 81 communities and 240,000 gas customers in 51 communities. NSTAR is an exempt public utility holding company under the provisions of the Public Utility Holding Company Act of 1935 and, in addition to its investment in the Company, has interests in various other utility and nonregulated companies.

The Company is a wholesale electric generating company organized in 1902 under the laws of the Commonwealth of Massachusetts. On December 30, 1998, in response to the significant changes that have taken place in the utility industry, COM/Energy sold substantially all of its non-nuclear generating assets, including the Company's generating station, to affiliates of The Southern Company of Atlanta, Georgia. The Company's generating stations, located in Sandwich, Massachusetts consisted of two units jointly-owned by the Company and Montaup Electric Company (Montaup) (an unaffiliated company). The Company continues to have a 3.52% interest in the Seabrook 1 nuclear power plant to provide a portion of the capacity and energy needs of affiliates Cambridge Electric Light Company (Cambridge Electric) and Commonwealth Electric Company (Commonwealth Electric).

The Company had 109 employees prior to the sale of Canal Units 1 and 2 on December 30, 1998; however, following the sale, the Company no longer has any employees.

(2) Significant Accounting Policies

(a) Accounting Principles

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

Certain prior year amounts are reclassified from time to time to conform with the presentation used in the current year's financial statements.

(b) Merger and Financial Statement Presentation

On August 25, 1999 BEC Energy (BEC) and Commonwealth Energy System (Com/Energy) merged to form NSTAR as an exempt public utility holding company. NSTAR's utility subsidiaries include Canal Electric Company (Canal Electric). The merger was accounted for by NSTAR as an acquisition by BEC of Com/Energy and all of its subsidiaries including Canal Electric Company under the purchase method of accounting.

In the accompanying statements, Canal Electric Company prior to the merger is labeled as the "Predecessor" and after the merger as the "Successor."

As a result of this merger, the fourth quarter dividend amounting to approximately $35 million was reflected as a return of capital and, as a result, reduced paid-in capital. As of August 25, 1999, approximately $54 million of retained earnings was reclassified as additional paid-in capital.

(c) Regulatory Assets

The Company is regulated as to rates, accounting and other matters by various authorities, including the Federal Energy Regulatory Commission (FERC) and the Massachusetts Department of Telecommunications and Energy (MDTE).

Based on the current regulatory framework, the Company accounts for the economic effects of regulation in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company has established various regulatory assets in cases where the FERC has permitted or is expected to permit recovery of specific costs over time. In the event the criteria for applying SFAS No. 71 are no longer met, the accounting impact would be an extraordinary, non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS No. 71 include: 1) increasing competition restricting the Company's ability to establish prices to recover specific costs, and 2) a significant change in the current manner in which rates are set by regulators from cost based regulation to another form of regulation. These criteria are reviewed on a regular basis to ensure the continuing application of SFAS No. 71 is appropriate. Based on the current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets are probable of future recovery.

The principal regulatory assets included in deferred charges at December 31, 1999 and 1998 were as follows:

	1999	1998
	(Dollars in thousands)	
Seabrook related costs	$1,572	$3,008
Deferred income taxes	17,401	15,737
Total regulatory assets	$18,973	$18,745

As of December 31, 1999, all of the Company's regulatory assets are reflected in rates charged to customers over a weighted average period of approximately 11 years beginning in 1998. Seabrook related costs as outlined above include approximately $20,000 in merger-related costs.

In November 1997, the Commonwealth of Massachusetts enacted the Massachusetts Electric Restructuring Act. On November 19, 1997, the Company, along with Cambridge Electric and Commonwealth Electric filed a restructuring plan with the MDTE that was approved by the MDTE on February 27, 1998. Commonwealth Electric and Cambridge Electric currently provide their standard offer customers service at inflation adjusted rates that are 15% lower than rates in effect prior to March 1, 1998, the retail access date. As part of the plan, the MDTE authorized the recovery of certain strandable costs and provides that certain future costs may be deferred to achieve or maintain the rate reductions that the restructuring bill mandates. The legislation gives the MDTE the authority to determine the amount of strandable costs that will be eligible for recovery. Costs that will qualify as strandable costs and be eligible for recovery include, but are not limited to, certain above market costs associated with generating facilities, costs associated with long-term commitments to purchase power at above market prices from independent power producers and regulatory assets and associated liabilities related to the generation portion of the electric business.

(d) Divestiture of Generation Assets

The cost of transitioning to competition have been mitigated, in part, by the sale of COM/Energy's non-nuclear generating assets. On May 27, 1998, COM/Energy agreed to sell substantially all of its non-nuclear generating assets (984 MW) to affiliates of The Southern Company of Atlanta, Georgia. The sale was conducted through an auction process that was outlined in a restructuring plan filed with the MDTE in November 1997 in conjunction with the state's industry restructuring legislation enacted in 1997. The sale was approved by the MDTE on October 30, 1998 and by the FERC on November 12, 1998. Proceeds from the sale of the Company's non-nuclear generating assets amounted to approximately $395 million or 6 times their book value of approximately $65.4 million. The proceeds from the sale, net of book value, transaction costs and certain other adjustments amounted to approximately $298 million and are being used to reduce transition costs of Cambridge Electric and Commonwealth Electric related to electric industry restructuring that otherwise would have been collected through a non-bypassable transition charge. An adjustment of $5.1 million was recorded in the first quarter of 1999 that reduced the book value to $60.3 million. The Company has determined that this transaction was not a taxable event because it provided no economic benefit to the Company.

COM/Energy established Energy Investment Services, Inc. as the vehicle to invest the net proceeds from the sale of the Company's generation assets. These proceeds are invested in a portfolio of securities that is designed to maintain principal and earn a reasonable return. Both the principal amount and income earned are being used to reduce the transition costs that would otherwise be billed to customers of Cambridge Electric and Commonwealth Electric.

(e) Transactions with Affiliates

Transactions between the Company and other NSTAR companies include purchases and sales of electricity, including the Company's acquisition and resale of capacity entitlements and related energy generated by certain units of other New England utilities. The Company has functioned as the principal supplier of electric generation capacity for and on behalf of affiliates Cambridge Electric and Commonwealth Electric, including nonconstruction costs related to the Seabrook generating unit. In addition, payments for management, accounting, data processing and other services are made to affiliated companies. Transactions with other COM/Energy companies are subject to review by the FERC and the MDTE.

The Company's operating revenues included the following intercompany amounts for the periods indicated:

Period	Electricity Sales (Canal Units)	Purchased Power	Seabrook Units and Other
		(Dollars in thousands)	
Jan.- Aug 24, 1999	$987	$3,473	$29,146
Aug. 25 – Dec. 31, 1999	-	-	13,055
1998	70,283	3,667	39,074
1997	76,859	8,885	39,159

(f) Other Major Customers

Prior to the sale of Canal Units 1 and 2 on December 30, 1998, the Company was a wholesale electric generating company selling power under life-of-the-unit contracts that were approved by FERC to Boston Edison Company (an affiliate since the merger with BEC Energy), Montaup Electric Company and New England Power Company. Each utility was obligated to purchase one-quarter of the capacity and energy of Canal Unit 1.

(g) Equity Method of Accounting

The Company uses the equity method of accounting for its 3.8% investment in the New England/Hydro-Quebec Phase II transmission facilities due in part to its ability to exercise significant influence over operating and financial policies of the entity. Under this method, it records as income the proportionate share of the net earnings of this project with a corresponding increase in the carrying value of the investment. The investment amount is reduced as cash dividends are received.

(h) Depreciation and Nuclear Fuel Amortization

Depreciation is provided using the straight-line method at rates intended to amortize the original cost and the estimated cost of removal less salvage of properties over their estimated economic lives. The Company's composite depreciation rate, based on average depreciable property in service, was 3.01% in 1999, 4.71% in 1998 and 4.45% in 1997.

The cost of nuclear fuel is amortized to fuel expense based on the quantity of energy produced. Nuclear fuel expense also includes a provision for the costs associated with the ultimate disposal of the spent nuclear fuel.

(i) Maintenance

Expenditures for repairs of property and replacement and renewal of items determined to be less than units of property were charged to maintenance expense. Additions, replacements and renewals of property considered to be units of property, were charged to the appropriate plant accounts. Upon retirement, accumulated depreciation was charged with the original cost of property units and the cost of removal net of salvage.

(j) Allowance for Funds Used During Construction

Under applicable rate-making practices, the Company is permitted to include an allowance for funds used during construction (AFUDC) as an element of its depreciable property costs. This allowance is based on the amount of construction work in progress that is not included in the rate base on which the Company earns a return. An amount equal to the AFUDC capitalized in the current period is reflected in the accompanying Statements of Income.

While AFUDC does not provide funds currently, these amounts are recoverable in revenues over the service life of the constructed property. The Company develops rates based upon its current cost of capital and used a compound rate of 5.75% in 1999, 5.75% in 1998 and 6% in 1997.

(3) Income Taxes

For financial reporting purposes, the Company provides federal and state income taxes on a separate return basis. However, for federal income tax purposes, the Company's taxable income and deductions are included in the consolidated income tax return of NSTAR (COM/Energy prior to the merger) the Parent and it makes tax payments or receives refunds on the basis of its tax attributes in the tax return in accordance with applicable regulations.

Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" (SFAS 109). SFAS 109 requires the recognition of deferred tax assets and liabilities for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities

Accumulated deferred income taxes consisted of the following:

	1999	1998
	(Dollars in thousands)	
Deferred tax liabilities		
Property-related	$65,815	$74,585
Seabrook nonconstruction	707	707
All other	611	1,832
	67,133	77,124
Deferred tax assets		
Investment tax credits	7,456	7,844
Regulatory liability	2,102	2,102
All other	3,458	2,244
	13,016	12,190
Net accumulated deferred income taxes	$54,117	$64,934

Previously deferred investment tax credits are amortized over the estimated remaining lives of the property giving rise to the credits. The net year-end deferred income tax liability above includes a current deferred tax liability of $2,141,000 and $551,000 in 1999 and 1998, respectively, which is included in accrued income taxes in the accompanying Balance Sheets.

Components of income tax expense were as follows:

	For the 1999 Periods			
	August 25 to December 31	January 1 to August 24	1998	1997
	(Successor)	(Predecessor)		
		(Dollars in thousands)		
Federal:				
Current income tax expenses	$10.129	$7.806	$109.267	$9.128
Deferred income tax expense	(6.834)	514	(6.775)	(764)
Investment tax credit amortization	(101)	(201)	(2.539)	(526)
	3,194	8.119	99.953	7.838
State:				
Current income tax expense	1.023	1.550	21.413	1.558
Deferred income tax expense	(354)	116	(776)	(133)
	669	1.666	20.637	1.425
			120.590	9.263
Amortization of regulatory liability relating to deferred income taxes	--	--	(122)	(76)
Total	$3,863	$9,785	$120,468	$9,187
Federal and state income taxes charged to:				
Operating expense	$3.863	$9.785	$8.168	$9.178
Other income	--	--	112.300	9
	$3,863	$9,785	$120,468	$9,187

The provision for income taxes in 1998 reflects the current tax related to the sale of the generating assets.

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

	For the 1999 Periods			
	August 25 to December 31	January 1 to August 24	1998	1997
	(Successor)	(Predecessor)		
Federal statutory tax rate	35%	35%	35%	35%
Federal income tax expense at statutory levels	$3,238	$8,680	$111,854	$8,405
Increase (Decrease) from statutory rate:				
Tax versus book depreciation	459	730	1,207	1,515
State tax, net of federal tax benefit	435	1,083	13,414	927
Sale of generation assets	-	-	(2,596)	-
Amortization of investment tax credits	(100)	(201)	(2,539)	(526)
Excess deferred reserves	-	-	(122)	(76)
Reversals of capitalized expenses	(200)	(446)	(561)	(560)
Other	31	(61)	(189)	(498)
	$3,863	$9,785	$120,468	$9,187
Effective federal tax rate	42%	39%	38%	38%

(4) Long-Term Debt and Interim Financing

(a) Long-Term Debt

On December 30, 1998, upon the sale of the Company's Units 1 and 2, a portion of the proceeds from the sale was used to retire all of the Company's long-term debt.

(b) Notes Payable to Banks

The Company and other NSTAR companies maintain both committed and uncommitted lines of credit for the short-term financing of their construction programs and other corporate purposes. As of December 31, 1999, COM/Energy companies had $115 million of committed lines of credit that will expire at varying intervals in 2000. These lines are normally renewed upon expiration and require annual fees of approximately .1875% of the outstanding balance. At December 31, 1998, COM/Energy's uncommitted lines of credit totaled $10 million. Interest rates on the Company's outstanding borrowings generally are money market rates and averaged 5.8% in both 1999 and 1998. The Company had notes payable to banks of $48,575,000 at December 31, 1999 and no notes outstanding at December 31, 1998.

(c) Advances from Affiliates

The Company had no short-term notes payable to COM/Energy at December 31, 1999 and 1998. These notes are written for a term of up to 11 months and 29 days. Interest is at the prime rate and is adjusted for changes in that rate during the terms of the notes. This rate averaged 8% in 1999 and 8.3% in 1998.

The Company is a member of the COM/Energy Money Pool (the Pool), an arrangement among the subsidiaries of COM/Energy, whereby short-term cash surpluses are used to help meet the short-term borrowing needs of the utility subsidiaries. In general, lenders to the Pool receive a higher rate of return than they otherwise would on such investments, while borrowers pay a lower interest rate than that available from banks. Interest rates on the outstanding borrowings are based on the monthly average rate the Company would otherwise have to pay banks, less one-half the difference between that rate and the monthly average U.S. Treasury Bill weekly auction rate. The borrowings are for a period of less than one year and are payable upon demand. The Company had $6,240,000 in borrowings from the Pool at December 31, 1999 and had no outstanding borrowings at December 31, 1998. Rates on these borrowings averaged 5.1% in 1999 and 5.3% in 1998.

(d) Disclosures About Fair Value of Financial Instruments

The carrying amount of cash, notes payable to banks and advances from affiliates approximates the fair value due to the short maturity of these financial instruments.

(5) Commitments and Contingencies

(a) Seabrook Nuclear Power Station

The Company's 3.52% interest in the Seabrook nuclear power station is to provide for a portion of the capacity and energy needs of Cambridge Electric and Commonwealth Electric. The Company is recovering 100% of its Seabrook 1 investment through power contracts pursuant to FERC and MDTE approval.

The Company and the other joint-owners have established a decommissioning fund to cover decommissioning costs. The estimated cost to decommission the plant is $509.8 million in current dollars. The Company's share of this liability (approximately $18 million), less its share of the market value of the assets held in a decommissioning trust (approximately $4 million), is approximately $14 million at December 31, 1999.

(b) Environmental Matters

The Company is subject to laws and regulations administered by federal, state and local authorities relating to the quality of the environment. These laws and regulations affect, among other things, the siting and operation of electric generating and transmission facilities and can require the installation of expensive air and water pollution control equipment. These regulations have had an impact on the Company's operations in the past; however their impact on future operations, capital costs and construction schedules is not expected to be significant since all of the Company's non-nuclear generating assets were sold in 1998.

Pursuant to the terms of the Canal Units 1 and 2 Asset Sale Agreement with Southern Energy dated May 15, 1998, the Company agreed to fund assessment work up to a $500,000 cap to address a condition of metals contamination found on the station site. Management is unable at this time to predict when closure on this issue will be determined.

(6) Employee Benefit Plans

Effective December 31, 1999, the pension and other postretirment benefit plans of BEC and COM/Energy were combined under NSTAR.

(a) Pension

The Company participates with other subsidiaries of NSTAR in a noncontributory pension plan with certain contributory features covering substantially all employees of NSTAR. Effective January 1, 2000, the defined benefit plan was amended to provide management employees lump sum benefits under a final average pay pension equity formula. Prior to January 1, 2000 these pension benefits were provide under a traditional final average pay formula. This amendment is reflected in the December 31, 1999 benefit obligation. It is the Company's policy to fund the Plan in amounts determined to meet the funding standards established by the Employee Retirement Income Security Act of 1974.

The funded status of the Plan cannot be presented separately for the Company since the Company participates in the Plan trust with other subsidiaries of NSTAR. Plan assets are available to provide benefits for all Plan participants. And are commingled.

The periodic costs (income) allocated to the company was $(20,000), $554,000 and $537,000 in 1999, 1998 and 1997, respectively. The accrued pension cost in the Company's statement of financial position was $1,911,000 and $465,000 in 1999 and 1998, respectively.

(b) Other Postretirement Benefits

Certain employees are eligible for postretirement benefits if they meet specific requirements. These benefits could include health and life insurance coverage and reimbursement of Medicare Part B premiums. Under certain circumstances, eligible employees are required to make contributions for postretirement benefits.

To fund postretirement benefits, the Company makes contributions to various voluntary employees' beneficiary association (VEBA) trusts that were established pursuant to section 501(c)(9) of the Internal Revenue Code (the Code). The Company also makes contributions to a subaccount of the COM/Energy pension plan and its successor pursuant to section 401(h) of the Code to fund a portion of its postretirement benefit obligation.

The funded status of the Plan cannot be presented separately for the Company since the Company participates in the Plan trusts and subaccount with other subsidiaries of NSTAR. Plan assets are available to provide benefits for all Plan participants who are former employees of the Company and of other subsidiaries of NSTAR.

The net periodic postretirement benefit cost allocated to the Company was $311,000, $610,000 and $655,000 in 1999, 1998 and 1997, respectively. The accrued benefit cost in the Company's statement of financial position was $2,863,000 and $0 at December 31, 1999 and 1998, respectively.

(c) Savings Plan

Prior to the sale of Units 1 and 2, the Company had an Employees Savings Plan that provided for Company contributions equal to contributions by eligible employees up to four percent of each employee's compensation rate and up to five percent for those employees no longer eligible for postretirement health benefits. The Company's contribution was $244,000 in 1998 and $256,000 in 1997.

(7) Lease Obligations

Prior to 1999 the Company leased equipment and office space under arrangements that are classified as operating leases. These lease agreements are for terms of one year or longer. These leases contained no provisions that prohibit the Company from entering into future lease agreements or obligations.

The Company has entered into support agreements with other participating New England utilities for 3.8% of the Hydro-Quebec Phase II transmission facilities and makes monthly support payments to cover depreciation and interest costs.

Future minimum lease payments, by period and in the aggregate, of capital leases consisted of the following at December 31, 1999:

	Capital Leases
	(Dollars in thousands)
2000	$1,699
2001	1,633
2002	1,572
2003	1,511
2004	1,450
Beyond 2004	13,850
Total future minimum lease payments	21,715
Less: Estimated interest element included therein	11,521
Estimated present value of future minimum lease payments	$10,464

Total rent expense for all operating leases, except those with terms of a month or less, amounted to $0 in 1999, $356,000 in 1998 and $575,000 in 1997. There were no contingent rentals and no sublease rentals for the years 1999, 1998 and 1997.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	232,493,313	232,493,313
4	Property Under Capital Leases	10,551,215	10,551,215
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	243,044,528	243,044,528
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	2,550,595	2,550,595
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	245,595,123	245,595,123
14	Accum Prov for Depr, Amort, & Depl	58,054,381	58,054,381
15	Net Utility Plant (13 less 14)	187,540,742	187,540,742
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	58,054,381	58,054,381
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant		
22	Total In Service (18 thru 21)	58,054,381	58,054,381
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	58,054,381	58,054,381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
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Name of Respondent	This Report Is:	Date of Report	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 12/31/1999	Dec. 31, 1999

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	290,319	
3	Nuclear Materials	1,002,031	-19,560
4	Allowance for Funds Used during Construction	275,686	326,285
5	(Other Overhead Construction Costs)		
6	SUBTOTAL (Total 2 thru 5)	1,568,036	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	4,183,765	
10	SUBTOTAL (Total 8 & 9)	4,183,765	
11	Spent Nuclear Fuel (120.4)	17,829,200	
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	20,456,737	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	3,124,264	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
[redacted]			1
[redacted]		290,319	2
[redacted]		982,471	3
[redacted]		601,971	4
[redacted]			5
[redacted]	[redacted]	1,874,761	6
[redacted]	[redacted]		7
			8
		4,183,765	9
[redacted]	[redacted]	4,183,765	10
		17,829,200	11
			12
-1,127,587		21,584,324	13
[redacted]	[redacted]	2,303,402	14
[redacted]	[redacted]		15
[redacted]	[redacted]		16
[redacted]	[redacted]		17
			18
			19
			20
			21
[redacted]	[redacted]		22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	315,932	
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	315,932	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)		
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	56,287	
18	(321) Structures and Improvements	74,490,160	
19	(322) Reactor Plant Equipment	102,946,151	
20	(323) Turbogenerator Units	16,881,161	
21	(324) Accessory Electric Equipment	24,268,356	
22	(325) Misc. Power Plant Equipment	7,553,600	
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	226,195,715	
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights		
26	(331) Structures and Improvements		
27	(332) Reservoirs, Dams, and Waterways		
28	(333) Water Wheels, Turbines, and Generators		
29	(334) Accessory Electric Equipment		
30	(335) Misc. Power PLant Equipment		
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)		
33	D. Other Production Plant		
34	(340) Land and Land Rights		
35	(341) Structures and Improvements		
36	(342) Fuel Holders, Products, and Accessories		
37	(343) Prime Movers		
38	(344) Generators		
39	(345) Accessory Electric Equipment		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			315,932		3
					4
			315,932		5
					6
					7
					8
					9
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					13
					14
					15
					16
			56,287		17
			74,490,160		18
			102,946,151		19
			16,881,161		20
			24,268,356		21
			7,553,600		22
			226,195,715		23
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment		
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)		
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	226,195,715	
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	101,298	
45	(352) Structures and Improvements	946,943	
46	(353) Station Equipment	7,726,242	
47	(354) Towers and Fixtures	2,338,196	
48	(355) Poles and Fixtures	1,460,376	
49	(356) Overhead Conductors and Devices	1,469,173	
50	(357) Underground Conduit		
51	(358) Underground Conductors and Devices		
52	(359) Roads and Trails	169,136	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	14,211,364	
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights		
56	(361) Structures and Improvements		
57	(362) Station Equipment		
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures		
60	(365) Overhead Conductors and Devices		
61	(366) Underground Conduit		
62	(367) Underground Conductors and Devices		
63	(368) Line Transformers		
64	(369) Services		
65	(370) Meters		
66	(371) Installations on Customer Premises		
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems		
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)		
70	5. GENERAL PLANT		
71	(389) Land and Land Rights		
72	(390) Structures and Improvements	931,237	22,048
73	(391) Office Furniture and Equipment	1,840,455	
74	(392) Transportation Equipment		
75	(393) Stores Equipment		
76	(394) Tools, Shop and Garage Equipment		
77	(395) Laboratory Equipment		
78	(396) Power Operated Equipment	133	
79	(397) Communication Equipment	1	
80	(398) Miscellaneous Equipment	95,403	
81	SUBTOTAL (Enter Total of lines 71 thru 80)	2,867,229	22,048
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	2,867,229	22,048
84	TOTAL (Accounts 101 and 106)	243,590,240	22,048
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	243,590,240	22,048

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					40
					41
			226,195,715		42
					43
	-5,678		95,620		44
	-54,505		892,438		45
	-245,840		7,480,402		46
	-137,966		2,200,230		47
	-65,860		1,394,516		48
			1,469,173		49
					50
					51
	-57,911		111,225		52
	-567,760		13,643,604		53
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			953,285		72
			1,840,455		73
					74
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					77
			133		78
			1		79
			95,403		80
			2,889,277		81
					82
			2,889,277		83
	-567,760		243,044,528		84
					85
					86
					87
	-567,760		243,044,528		88

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Joint-Owned Project - Seabrook Unit 1	2,539,794
2		
3	Minor Projects	10,801
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43	TOTAL	2,550,595

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in column (a) to kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items. 2. On Page 218 furnish information concerning construction overheads. 3. A respondent should not report "none" to the page if no overhead apportionments are made, but rather should explain on Page 218 the accounting procedures, employed and the amounts of engineering, supervision and administrative costs, etc. which are directly charged to construction. 4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of overhead (a)	Total amount charged for the year (b)
1	Allowance for Funds Used During Construction	120,363
2	Construction Accounting Services	458
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46	TOTAL	120,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant instructions 3(17) of the U.S. of A.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

AFUDC is calculated in accordance with Ferc Order #561.

Construction Accounting Services consists of labor of personnel necessary to account for construction: It is applied on the ratio of such service costs to gross additions to the plant.

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio(Percent) (c)	Cost Rate Percentage (d)
1	Average Short-Term Debt & Computation of Allowance text	S 28,987,055	[redacted]	[redacted]
2	Short-term Interest	[redacted]	[redacted]	s 5.70
3	Long-Term Debt	D		d
4	Preferred Stock	P		p
5	Common Equity	C 288,365,879	100.00	c 11.72
6	Total Capitalization	288,365,879	100%	[redacted]
7	Average Construction Work in Progress Balance	W 3,898,573	[redacted]	[redacted]

2. Gross Rate for Borrowed Funds $s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$ 5.70

3. Rate for Other Funds $\left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$ 0.00

4. Weighted Average Rate Actually Used for the Year:
   a. Rate for Borrowed Funds - 5.75
   b. Rate for Other Funds - 0.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	56,624,360	56,624,360		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	6,582,000	6,582,000		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	6,582,000	6,582,000		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	5,151,979	5,151,979		
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	5,151,979	5,151,979		
15	Other Debit or Cr. Items (Describe):				
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	58,054,381	58,054,381		
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production				
19	Nuclear Production	58,054,381	58,054,381		
20	Hydraulic Production-Conventional				
21	Hydraulic Production-Pumped Storage				
22	Other Production				
23	Transmission				
24	Distribution				
25	General				
26	TOTAL (Enter Total of lines 18 thru 25)	58,054,381	58,054,381		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of Nonutility property included in Account 121.
2. Designate with a double asterisk any property which is Leased to another company. State name of Lessee and whether Lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is Less) may be-grouped by (1) previously devoted to public service (Line 44), or (2) other Nonutility property (Line 45).

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	Land - Purchased 10 acres in Plymouth, MA in 1994.			
2	Leased to Commonwealth Electric Company-Associated Co.	8,994		8,994
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43				
44	Minor Item Previously Devoted to Public Service			
45	Minor Items-Other Nonutility Property			
46	TOTAL	8,994	0	8,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	New England Hydro-Transmission Electric Company-			
2	Common Stock			1,780,782
3	Stock Repurchase			-145,026
4	Equity and Dividends			82,828
5	Subtotal			1,718,584
6				
7				
8	New England Hydro-Transmission Corporation-			
9	Common Stock			1,142,307
10	Stock Repurchase			-115,910
11	Equity and Dividends			55,136
12	Subtotal			1,081,533
13				
14				
15				
16				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	2,800,117

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1,635,756		2
		-134,350		3
381,033	226,507	237,354		4
381,033	226,507	1,738,760		5
				6
				7
				8
		1,026,397		9
		-95,002		10
246,084	137,896	163,324		11
246,084	137,896	1,094,719		12
				13
				14
				15
				16
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				41
627,117	364,403	2,833,479		42

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			Electric product.
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	1,266,731	1,307,916	Electric product.
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to - Other			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	1,266,731	1,307,916	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	898	3,518	Electric product.
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	1,267,629	1,311,434	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2000 No. (d)	2000 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	The Southern Company				
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinguished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2001		2002		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
				763,500.00		763,500.00		1
[redacted]								2
								3
								4
								5
[redacted]								6
								7
								8
				-763,500.00		-763,500.00		9
								10
								11
								12
								13
								14
				-763,500.00		-763,500.00		15
[redacted]								16
								17
								18
[redacted]								19
								20
[redacted]								21
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								28
								29
[redacted]								30
								31
								32
								33
								34
								35
[redacted]								
				19,250.00		19,250.00		36
								37
								38
				19,250.00		19,250.00		39
								40
[redacted]								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	NONE					
2						
3						
4						
5						
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7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Abandonment of Seabrook Nuclear	850,406	2,830			853,236
22	Generating Unit #2					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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41						
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43						
44						
45						
46						
47						
48						
49	TOTAL	850,406	2,830	[redacted]		853,236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	FASB #109 Income Taxes Surplus net of Deficiences	2,312,039	283/409	648,071	17,401,029
2					
3					
4					
5					
6	Seabrook Unit No. 1 -		406	1,319,436	655,732
7	Non-Construction Pre-Operating Cost				
8	7/1/90 - 6/20/00				
9					
10					
11					
12					
13	Department of Energy Assessment for		518	197,448	-14,582
14	Decontamination and Decommissioning				
15					
16					
17					
18					
19					
20	ISO - Reorganization Costs	11,463	920	923	57,277
21					
22					
23					
24					
25					
26					
27					
28					
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30					
31					
32					
33					
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43					
44	TOTAL	2,323,502		2,165,878	18,099,456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deffered Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Seabrook Deferred Charges	258,043	95,679	253	80,955	272,767
2						
3	Com/Energy Services Charges	10,416	52,461	920	56,742	6,135
4	Com/Energy Services Charges	606	2,749	921	2,963	392
5						
6						
7	Undistributed Payroll	3,654		Various	3,654	
8						
9	Auction	112,167	1,141,155	Various	1,190,686	62,636
10						
11	Seabrook 2 Generator Sale	50,327		253	50,327	
12						
13	Supplemental Pension Payments	142,843	251,295	253	394,138	
14						
15	FASB 87 Payments	718,930	1,322,657	253	718,930	1,322,657
16						
17	Minor Items	-2,459	7,377	Various		4,918
18						
19	Corporate Owned Life Insurance	61,381				61,381
20						
21	Postretirement	429,698	345,079	253	429,698	345,079
22						
23	1997 Diesel Tax Relief	38,517		131	27,515	11,002
24						
25	EPA Allowance Auction	48,696		253	48,696	
26						
27						
28						
29						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,872,819				2,086,967

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pension Plan	718,672	995,953
3	Insurance Expense	339,382	
4	Seabrook II Abandonment	2,086,099	
5			
6			
7	Other	204,766	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	3,348,919	995,953
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	3,348,919	995,953

Notes

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	2,328,200	25.00	
2				
3				
4	Note:			
5	The Board of Directors, on October 28, 1983,			
6	approved 805,000 shares of $25 par value common			
7	stock. The Massachusetts DTE in order #1657,			
8	on December 9, 1983, approved the issuance of			
9	these shares. At the time of this filing, the			
10	shares are still unissued.			
11				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,523,200	38,080,000					1
						2
						3
						4
						5
						6
						7
						8
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION PREMIUM ON CAPITAL AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For Premium on Account 207, Capital Stock, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of shares (b)	Amount (c)
1	Account 207		
2			
3	Premium on Capital Stock	1,523,200	8,320,729
4			
5			
6			
7			
8			
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46	TOTAL	1,523,200	8,320,729

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock, $25 par value	12,019
2		
3		
4		
5		
6		
7		
8		
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21		
22	TOTAL	12,019

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	20,403,719
2		
3		
4	Taxable Income Not Reported on Books	
5		
6	Sale of Generation Assets	98,106,572
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Depreciation and Amortization	6,582,000
11	Federal Income and MA State Franchise Tax	-96,851,374
12	Other	1,800,623
13	Amortization of Investment Tax Credit	301,124
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Allowable Depreciation	5,444,949
21	State Franchise Tax	1,618,351
22		
23		
24		
25		
26		
27	Federal Tax Net Income	23,279,364
28	Show Computation of Tax:	
29		
30	Taxable Income	24,897,715
31	Estimated State Tax	1,618,351
32	Total Federal Taxable Income	23,279,364
33		
34	Estimated Federal Income Tax Payable	8,147,777
35		
36	Intercompany Elimination - Dividend Paid	238,212,030
37		
38		
39		
40		
41	Footnote - Tax for the members of the consolidated	
42	group has not yet been determined.	
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal Income Tax	101,670,548		17,934,613	14,282,046	-92,439,821
2						
3	State Franchise Tax	19,491,195		2,573,483	1,591,312	-18,360,851
4						
5	Real Estate and Personal					
6	Property Tax	500		935,230	935,730	
7						
8	Federal Old Age Benefit Tax	29,623		185,654	214,787	
9						
10	Federal Unemployment Tax	61		4,065	4,133	
11						
12	State Unemployment Tax	227		10,684	10,934	
13						
14	Seabrook 1 payroll tax			167,677	167,677	
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	121,192,154		21,811,406	17,206,619	-110,800,672

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
12,883,294		17,934,613				1
						2
2,112,515		2,573,483				3
						4
						5
		935,230				6
						7
490		142,155			43,499	8
						9
-7		3,090			975	10
						11
-23		9,410			1,274	12
						13
		167,677				14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
14,996,269		21,765,658			45,748	41

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Begining of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	8,427,481			411.4	301,124	
6							
7							
8	TOTAL	8,427,481				301,124	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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48							

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
8,126,357			5
			6
			7
8,126,357			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			23
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			45
			46
			47
			48

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deffered Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Supplemental Pension Plan	1,599,894	926/186	345,095	134,135	1,388,934
2						
3	Employee Pension Plan	1,541,367				1,541,367
4						
5	Seabrook 2 Cost of Removal	484,200				484,200
6						
7	Seabrook 2 Sale of Steam Generator	2,044,441	186	50,327		1,994,114
8						
9	Employee Salary Continuation Plan	199,839	926/232	201,762	12,720	10,797
10						
11	Excess Pension Benefit	72,743	926	27,056		45,687
12						
13	Seabrook 1 Deferred Credits	116,060	228/186	140,000	23,940	
14						
15	Decommissioning Trust Fund per					
16	Docket #FA93-30-000	2,985,822			842,842	3,828,664
17						
18	Supplemental Pension Interest	10,597				10,597
19						
20	Long Term Disability	84,312				84,312
21						
22	NU-Slice DOE Refund	85,604				85,604
23						
24	Algonquin Support Charges	219,299				219,299
25						
26	Postretirement Benefits	34,653	Various	34,653		
27						
28	Environmental Reserve	500,000				500,000
29						
30	Short Term Interest Income	23,537	431	23,537		
31						
32	Worker's Compensation				167,000	167,000
33						
34	Auto Liability				154,000	154,000
35						
36	Repair Liability				66,000	66,000
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	10,002,368		822,430	1,400,637	10,580,575

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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	6,375,738		3,987,228
5	Other			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	6,375,738		3,987,228
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	6,375,738		3,987,228
18	Classification of TOTAL			
19	Federal Income Tax	5,319,211		3,326,502
20	State Income Tax	1,056,527		660,726
21	Local Income Tax			

NOTES

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ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
							2
							3
						2,388,510	4
							5
							6
							7
						2,388,510	8
[redacted]							9
							10
							11
							12
							13
							14
							15
							16
						2,388,510	17
[redacted]							18
						1,992,709	19
						395,801	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	43,249,331	47,214	4,596,470
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	43,249,331	47,214	4,596,470
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	43,249,331	47,214	4,596,470
10	Classification of TOTAL			
11	Federal Income Tax	36,089,697	39,390	3,834,786
12	State Income Tax	7,159,634	7,824	761,684
13	Local Income Tax			

NOTES

Name of Respondent CANAL ELECTRIC COMPANY	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/1999	Year of Report Dec. 31, 1999

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
[redacted]							1
				146	-5,968,226	32,731,849	2
							3
							4
					-5,968,226	32,731,849	5
							6
							7
							8
					-5,968,226	32,731,849	9
[redacted]							10
					-5,968,226	26,326,075	11
						6,405,774	12
							13

NOTES (Continued)

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Seabrook Unit 1 Non-Constructi	646,858		517,549
4	Regulatory Asset Due to FAS #	16,378,342		
5	state TAx Apportionment	235,452		
6				
7				
8	Other	1,396,557	686,414	
9	TOTAL Electric (Total of lines 3 thru 8)	18,657,209	686,414	517,549
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other Specify			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	18,657,209	686,414	517,549
20	Classification of TOTAL			
21	Federal Income Tax	18,562,987	572,668	431,786
22	State Income Tax	94,222	113,746	85,763
23	Local Income Tax			

NOTES

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						129,309	3
				182	1,022,687	17,401,029	4
						235,452	5
							6
							7
				236	143,595	2,226,566	8
					1,166,282	19,992,356	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
					1,166,282	19,992,356	19
							20
					973,017	19,676,886	21
					193,265	315,470	22
							23

NOTES (Continued)

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ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales		
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)		
5	Large (or Ind.) (See Instr. 4)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers		
11	(447) Sales for Resale	43,571,641	176,885,016
12	TOTAL Sales of Electricity	43,571,641	176,885,016
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	43,571,641	176,885,016
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property		982,833
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,770,755	4,130,008
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	3,770,755	5,112,841
27	TOTAL Electric Operating Revenues	47,342,396	181,997,857

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ELECTRIC OPERATING REVENUES (Account 400)

4. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increase or decreases.
6. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
[redacted]				1
				2
[redacted]				3
				4
				5
				6
				7
				8
				9
				10
306,012	4,917,664	5	6	11
306,012	4,917,664	5	6	12
				13
306,012	4,917,664	5	6	14

Line 12, column (b) includes $ 717,000 of unbilled revenues.

Line 12, column (d) includes 0 MWH relating to unbilled revenues

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected toad for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	(a)Cambridge Electric Light Company					
2	Note (1) (4) Canal 1	LU	4	28	28	N/A
3	Note (2) (4) Canal 2	LU	17	58	58	N/A
4	Note (3) Seabrook	LU	33	8	8	N/A
5						
6	(a) Commonwealth Electric Company					
7	Note (1) (4) Canal 1	LU	4	112	113	N/A
8	Note (2) (4) Canal 2	LU	17	148	184	N/A
9	Note (3) Seabrook	LU	33	33	33	N/A
10						
11	Boston Edison Company - Note (1) (4)	LU	1	143	140	N/A
12	Montaup Electric Company - Note (1) (4)	LU	2	143	140	N/A
13	New England Power Co. - Note (1) (4)	LU	3	143	140	N/A
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
	22,034	206	-33,300	-11,060	2
	154,347	13,717	1,000	169,064	3
61,019	8,085,151	286,627	-10,768	8,361,010	4
					5
					6
	88,466	829	-133,700	-44,405	7
	619,710	55,075	4,003	678,788	8
244,993	32,462,249	1,150,830	-43,232	33,569,847	9
					10
	110,499	1,035	-167,000	-55,466	11
	1,125,294	1,035	-167,000	959,329	12
	110,499	1,035	-167,000	-55,466	13
					14
0	0	0	0	0	
306,012	42,778,249	1,510,389	-716,997	43,571,641	
306,012	42,778,249	1,510,389	-716,997	43,571,641	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	-24,060	2,114,612
5	(501) Fuel	106,290	88,295,748
6	(502) Steam Expenses	48,010	1,987,009
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		171,771
9	(505) Electric Expenses	27,836	2,299,604
10	(506) Miscellaneous Steam Power Expenses	300,185	4,194,261
11	(507) Rents	-179	605,501
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	458,082	99,324,964
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	823	306,278
16	(511) Maintenance of Structures	12,885	541,419
17	(512) Maintenance of Boiler Plant	45,726	7,953,107
18	(513) Maintenance of Electric Plant	33,467	2,025,588
19	(514) Maintenance of Miscellaneous Steam Plant	2,836	204,733
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	95,737	11,031,125
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	553,819	110,356,089
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	826,232	916,680
25	(518) Fuel	1,437,496	1,273,274
26	(519) Coolants and Water	76,795	73,859
27	(520) Steam Expenses	598,914	459,357
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	159,253	150,784
31	(524) Miscellaneous Nuclear Power Expenses	990,363	1,008,711
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	4,089,053	3,882,665
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	387,350	386,767
36	(529) Maintenance of Structures	117,238	289,301
37	(530) Maintenance of Reactor Plant Equipment	745,488	351,879
38	(531) Maintenance of Electric Plant	587,466	396,737
39	(532) Maintenance of Miscellaneous Nuclear Plant	17,594	10,973
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	1,855,136	1,435,657
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	5,944,189	5,318,322
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power		-3,068
77	(556) System Control and Load Dispatching	5,102	148,468
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	5,102	145,400
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	6,503,110	115,819,811
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering		
84	(561) Load Dispatching		
85	(562) Station Expenses		
86	(563) Overhead Lines Expenses		
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	3,661,612	3,863,988
89	(566) Miscellaneous Transmission Expenses	20	15,762
90	(567) Rents		
91	TOTAL Operation (Enter Total of lines 83 thru 90)	3,661,632	3,879,750
92	Maintenance		
93	(568) Maintenance Supervision and Engineering		
94	(569) Maintenance of Structures		
95	(570) Maintenance of Station Equipment	4,748	526
96	(571) Maintenance of Overhead Lines		
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant		
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	4,748	526
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	3,666,380	3,880,276
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching		
106	(582) Station Expenses		
107	(583) Overhead Line Expenses		
108	(584) Underground Line Expenses		
109	(585) Street Lighting and Signal System Expenses		
110	(586) Meter Expenses		
111	(587) Customer Installations Expenses		
112	(588) Miscellaneous Expenses		
113	(589) Rents		
114	TOTAL Operation (Enter Total of lines 103 thru 113)		
115	Maintenance		
116	(590) Maintenance Supervision and Engineering		
117	(591) Maintenance of Structures		
118	(592) Maintenance of Station Equipment		
119	(593) Maintenance of Overhead Lines		
120	(594) Maintenance of Underground Lines		
121	(595) Maintenance of Line Transformers		
122	(596) Maintenance of Street Lighting and Signal Systems		
123	(597) Maintenance of Meters		
124	(598) Maintenance of Miscellaneous Distribution Plant		
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)		
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)		
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision		
130	(902) Meter Reading Expenses		
131	(903) Customer Records and Collection Expenses		
132	(904) Uncollectible Accounts		
133	(905) Miscellaneous Customer Accounts Expenses		
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)		
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		
138	(908) Customer Assistance Expenses		7,650
139	(909) Informational and Instructional Expenses		
140	(910) Miscellaneous Customer Service and Informational Expenses		
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)		7,650
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	805,880	2,538,394
152	(921) Office Supplies and Expenses	60,270	444,000
153	(Less) (922) Administrative Expenses Transferred-Credit	-7,176	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	137,321	313,758
156	(924) Property Insurance	61,283	261,625
157	(925) Injuries and Damages	69,492	805,800
158	(926) Employee Pensions and Benefits	719,580	2,908,286
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	300,083	536,798
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	3,430	7,557
163	(930.2) Miscellaneous General Expenses	102,083	124,549
164	(931) Rents		186,190
165	TOTAL Operation (Enter Total of lines 151 thru 164)	2,266,598	8,126,957
166	Maintenance		
167	(935) Maintenance of General Plant	18,958	532
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	2,285,556	8,127,489
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	12,455,046	127,835,226

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employes on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/25/1999
2. Total Regular Full-Time Employees	0
3. Total Part-Time and Temporary Employees	0
4. Total Employees	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last Line. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	"Received Power from						
2	Wheeler"						
3	*						
4	(a),(b) Vermont Electr.			189,759			189,759
5	Transmission Company						
6	(a),(c) New England			331,989			331,989
7	Electr. Transmiss. Co.						
8	(a),(d) Public Service			109,903			109,903
9	Co. of New Hampshire						
10	(a),(e) New England			134,300			134,300
11	Power Company						
12							
13							
14							
15							
16							
	TOTAL			3,661,612			3,661,612

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide transmission service. Provide the full name of the company; abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last Line. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY: Magawatt-hours Received (b)	TRANSFER OF ENERGY: Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	(a), (f) New England			375,597			375,597
2	Power Company						
3	(a),(f) Boston Edison			17,687			17,687
4	Company						
5	(a),(f) New England			1,192,280			1,192,280
6	Hydro-Transm. Corp						
7	(a),(f) New England			1,310,097			1,310,097
8	Hydro-Transm Electr Co						
9							
10							
11							
12							
13							
14							
15							
16							
	TOTAL			3,661,612			3,661,612

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	61,332
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Seabrook 1 Miscellaneous General Expenses	21,974
8		
9	Montaup Billing Adjustment	14,922
10		
11	Minor Items (9)	3,855
12		
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46	TOTAL	102,083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant				
2	Steam Product Plant				
3	Nuclear Production Plant	6,582,000			6,582,000
4	Hydraulic Production Plant-Conventional				
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant				
7	Transmission Plant				
8	Distribution Plant				
9	General Plant				
10	Common Plant-Electric				
11	TOTAL	6,582,000			6,582,000

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Seabrook 1 Original						
13	Investment						
14	302	316	36.30		2.79	Forecast	
15	321	73,728	36.30		2.79	Forecast	
16	322	101,696	36.30		2.79	Forecast	
17	323	16,403	36.30		2.79	Forecast	
18	324	23,716	36.30		2.79	Forecast	
19	325	7,141	36.30		2.79	Forecast	
20	Subtotal	223,000					
21							
22	353	2,999	36.30		2.79	Forecast	
23	Subtotal	2,999					
24							
25	390	929	18.00		5.64	Forecast	
26	391	1,665	18.00		5.64	Forecast	
27	396		18.00		5.64	Forecast	
28	398	96	18.00		5.64	Forecast	
29	Subtotal	2,690					
30							
31	Seabrook 1 Additional						
32	Investment						
33	321	762	36.30		3.10	Forecast	
34	322	1,251	36.30		3.10	Forecast	
35	323	478	36.30		3.10	Forecast	
36	324	552	36.30		3.10	Forecast	
37	325	412	36.30		3.10	Forecast	
38	Subtotal	3,455					
39							
40	353	94	36.30		3.10	Forecast	
41	Subtotal	94					
42							
43	390	2	18.00		5.64	Forecast	
44	391	175	18.00		5.64	Forecast	
45	398				5.64	Forecast	
46	Subtotal	177					
47							
48	Total	232,415					
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges account. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425): Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions: Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Account 426	
2		
3	426.1 Donation	1,831
4	North Atlantic Energy Service Corp.-Agent Seabrook 1	3,462
5	Miscellaneous	250
6		
7	426.1	
8	Officier's Life Insurance	2,143
9		
10	426.3 Penalties	
11	Internal Revenue Service	70,984
12		
13	426.4 Civic, Political and Related Activities	
14	North Atlantic Energy Service Corp.-Agent Seabrook 1	1,706
15		
16	426.5 Other Deductions	
17	North Atlantic Energy Service Corp.-Agent Seabrook 1	7,772
18	Total - 426	88,148
19		
20	Account 430 Interest on Debt to Associated Companies	
21	Various Associated Companies-Money Pool (Note A)	333,729
22	Total - 430	333,729
23		
24	Account 431 Other Interest Expense	
25	Short Term Note Payable - Banks (Note B)	1,319,540
26	Interest on Income Tax Liability (Note B)	2,387,740
27	Miscellaneous	27,611
28	Total - 431	3,734,891
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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Massachusetts Department of Public Utilities				
2	MPDU 95-30 Electric Industry Restructuring		3,293	3,293	
3					
4	Minor Items		858	858	
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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40					
41					
42					
43					
44					
45					
46	TOTAL		4,151	4,151	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
		3,293					2
							3
		858					4
							5
							6
							7
							8
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							44
							45
		4,151					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	
4	Nuclear	306,012
5	Hydro-Conventional	
6	Hydro-Pumped Storage	
7	Other	
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	306,012
10	Purchases	
11	Power Exchanges:	
12	Received	
13	Delivered	
14	Net Exchanges (Line 12 minus line 13)	
15	Transmission For Other (Wheeling)	
16	Received	
17	Delivered	
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	306,012

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	306,012
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	306,012

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

MONTHLY PEAKS AND OUTPUT

1. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report in column (b) the system's energy output for each month such that the total on Line 41 matches the total on Line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on Line 24. include in the monthly amounts any energy losses associated with the sales so that the total on Line 41 exceeds the amount on Line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt Load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c)
5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	30,293	30,293		0	
30	February	27,456	27,456		0	
31	March	25,143	25,143		0	
32	April				0	
33	May	13,202	13,202		0	
34	June	29,450	29,450		0	
35	July	30,438	30,438		0	
36	August	30,409	30,409		0	
37	September	29,397	29,397		0	
38	October	30,439	30,439		0	
39	November	29,409	29,409		0	
40	December	30,376	30,376		0	
41	TOTAL	306,012	306,012			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Seabrook 1 (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Fully Contained	
3	Year Originally Constructed	1990	
4	Year Last Unit was Installed	1990	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1197.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	1164	0
7	Plant Hours Connected to Load	7566	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1158	0
10	When Limited by Condenser Water	1158	0
11	Average Number of Employees	840	0
12	Net Generation, Exclusive of Plant Use - KWh	306012340	0
13	Cost of Plant: Land and Land Rights	56287	0
14	Structures and Improvements	74490160	0
15	Equipment Costs	151649268	0
16	Total Cost	226195715	0
17	Cost per KW of Installed Capacity (line 5)	188.9689	0.0000
18	Production Expenses: Oper, Supv, & Engr	826232	0
19	Fuel	1437496	0
20	Coolants and Water (Nuclear Plants Only)	76795	0
21	Steam Expenses	598914	0
22	Steam From Other Sources	0	0
23	Steam Transferred (Cr)	0	0
24	Electric Expenses	159253	0
25	Misc Steam (or Nuclear) Power Expenses	990363	0
26	Rents	0	0
27	Allowances	0	0
28	Maintenance Supervision and Engineering	387350	0
29	Maintenance of Structures	117238	0
30	Maintenance of Boiler (or reactor) Plant	745488	0
31	Maintenance of Electric Plant	587466	0
32	Maintenance of Misc Steam (or Nuclear) Plant	17594	0
33	Total Production Expenses	5944189	0
34	Expenses per Net KWh	0.0194	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Nuclear				
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Grams				
37	Quantity (units) of Fuel Burned	0	49171	0	0	0	0
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	62500000	0	0	0	0
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	29.235	0.000	0.000	0.000	0.000
40	Average Cost of Fuel per Unit Burned	0.000	29.235	0.000	0.000	0.000	0.000
41	Average Cost of Fuel Burned per Million BTU	0.000	0.468	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.005	0.000	0.000	0.000	0.000
43	Average BTU per KWh Net Generation	0.000	10045.000	0.000	0.000	0.000	0.000

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, Liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.
2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgment where direct comparisons are not available. Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations. Examples of these costs would include a portion of the costs of tall smokestacks, underground Lines, and landscaped substations. Explain such costs in a footnote.
3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimations on a percentage of plant basis. Explain such estimations in a footnote.
4. Report all costs under the major classifications provided below and include, as a minimum, the items Listed-hereunder:

A. Air pollution control facilities:
(1) Scrubbers, precipitators, tall smokestacks, etc.
(2) Changes necessary to accommodate use of environmentally clean fuels such as Low ash or low sulfur fuels including storage and handling equipment
(3) Monitoring equipment
(4) Other.

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc.
(2) Waste water treatment equipment
(3) Sanitary waste disposal equipment
(4) Oil interceptors
(5) Sediment control facilities
(6) Monitoring equipment
(7) Other.

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment
(2) Land
(3) Settling ponds
(4) Other.

D. Noise abatement equipment:
(1) Structures
(2) mufflers
(3) Sound proofing equipment
(4) Monitoring equipment
(5) Other.

E. Esthetic costs:
(1) Architectural costs
(2) Towers
(3) Underground lines
(4) Landscaping
(5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
(1) Preparation of environmental reports
(2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
(3) Parks and related facilities
(4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).
6. Report construction work in progress relating to environmental facilities at Line 9.

Line No.	Classification of Cost (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	1,106	65		1,764,373	1,764,373
2	Water Pollution Control Facilities	15,655	65		9,803,755	9,803,755
3	Solid Waste Disposal Costs				645,816	645,816
4	Noise Abatement Equipment					
5	Esthetic Costs					
6	Additional Plant Capacity					
7	Miscellaneous (Identify significant)				560,859	560,859
8	TOTAL (Total of lines 1 thru 7)	16,761	130		12,774,803	12,774,803
9	Construction Work in Progress					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/1999	Dec. 31, 1999

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on Page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.
2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.
3. Report expenses under the subheadings listed below.
4. Under Item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.
5. Under Item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.
6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under Item 8 licensing and similar fees on such facilities.
7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expenses (a)	Amount (b)	Actual Expenses (c)
1	Depreciation		
2	Labor, Maint, Mtrls, & Supplies Cost Related to Env Fac & Programs	76,438	76,438
3	Fuel Related Costs		
4	Operation of Facilities		
5	Fly Ash and Sulfur Sludge Removal		
6	Difference in Cost of Environmentally Clean Fuels		
7	Replacement Power Costs		
8	Taxes and Fees		
9	Administrative and General		
10	Other (Identify significant)		
11	TOTAL	76,438	76,438

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	12/31/1999	Dec 31, 1999

FOOTNOTE DATA

Schedule Page: 114 Line No.: 6 Column: c

<PAGE 114 LINE 6 COL C&D>

INCLUDES NUCLEAR DECOMMISSIONING EXPENSE OF $409,548.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) X An Original (2) _ A Resubmission	12/31/1999	Dec 31, 1999

FOOTNOTE DATA

Schedule Page: 118 Line No.: 1 Column: c

FOOTNOTES:

STATEMENT OF RETAINED EARNINGS FOR THE YEAR - 1998 (P118-119)

LINE #	UNAPPROPRIATED RETAINED EARNINGS (ACCOUNT 216)	AMOUNT
1	BALANCE - BEGINNING OF YEAR	53,161,499
16	BALANCE TRANSFERRED FROM INCOME (ACCOUNT 433 LESS 418.1)	198,662,595
31	DIVIDENDS DECLARED - COMMON STOCK	10,281,600
36	TOTAL DIVIDENDS DECLARED - COMMON STOCK	10,281,600
37	TRANSFERS FROM ACCT. 216.1, UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS	728,632
38	BALANCE - END OF YEAR	242,271,126
48	TOTAL RETAINED EARNINGS (ACCOUNTS 215, 215.1, 216)	242,271,126

UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)

49	BALANCE - BEGINNING OF YEAR	-31,363
50	EQUITY IN EARNINGS FOR YEAR (ACCOUNT 418.1)	454,021
51	(LESS) DIVIDENDS RECEIVED (DEBIT)	728,632
53	BALANCE - END OF YEAR	-305,974

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
CANAL ELECTRIC COMPANY	(1) X An Original (2) __ A Resubmission	12/31/1999	Dec 31, 1999

FOOTNOTE DATA

Schedule Page: 120 Line No.: 2 Column: b

< PAGE 120 >
STATEMENT OF CASH FLOW FOR 1998

Ln 1	Net Cash Flow from Operating Activities:	
Ln 2	Net Income	199,116,616
Ln 3	Noncash Charges (Credits) to Income:	
Ln 4	Depreciation and Depletion	20,137,250
Ln 5	Amortization of:	
Ln 6	Seabrook Unit 1	1,319,436
Ln 7	Debt Premium and Expense	2,564,685
Ln 8	Deferred Income Taxes (net)	-7,673,669
Ln 9	Investment Tax Credit Adjustment (net)	-2,539,205
Ln 10	Net (Increase) Decrease in Receivables	-38,630,265
Ln 11	Net (Increase) Decrease in Inventory	823,389
Ln 13	Net Increase (Decrease) in Payables	134,779,811
Ln 14	Net (Increase) Decrease in Regulatory Assets	-1,311,307
Ln 17	(Less) Undistributed Earnings from Subsidiary	464,900
Ln 18	Other: Dividends from Subsidiary Companies	739,512
Ln 19	Other	-6,749,867
Ln 22	Net Cash Provided by Operating Companies	302,111,486
Ln 24	Cash Flows from Investment Activities:	
Ln 25	Construction and Acquisition of Plant:	
Ln 26	Gross Additions to Utility Plant	-4,794,011
Ln 27	Gross Additions to Nuclear Fuel	-1,374,475
Ln 31	Sale of Generating Assets (net)	78,414,129
Ln 34	Cash Outflows for Plant	72,245,643
Ln 39	Investments in and Advances to Associated and Subsidiary Companies	-258,925,000

< PAGE 121 >
STATEMENT OF CASH FLOW FOR 1998

Ln 57	Net Cash Used in Investing Activities	-186,679,357
Ln 59	Cash Flows from Financing Activities:	
Ln 72	Payments for Retirement of:	
Ln 73	Long-Term Debt	-84,300,000
Ln 78	Net Decrease in Short-Term Debt	-20,850,000
Ln 81	Dividends on Common Stock	-10,281,600
Ln 83	Net Cash Used in Financing Activities	-115,431,600
Ln 86	Net Decrease in Cash and Cash Equivalents	529
Ln 88	Cash and Cash Equivalents at Beginning of Year	18,307
Ln 90	Cash and Cash Equivalents at End of Year	18,836

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 218   Line No.: 8   Column: Item 4a

<PAGE 218 LINE 4>

DISCOUNTED RATE

Schedule Page: 262 Line No.: 1 Column: f

FOOTNOTES:

LINE 1 & 2 Since the Company has determined that the sale of generating assets transaction made on December 30, 1998 was not a taxable event because it provided no economic benefit to the Company, both Federal Income and State Franchise taxes accrued, have been adjusted to remove the current income tax liability of $92,439,821 (Federal) and $18,360,851 (State Franchise).

< PAGE 263 ROW 8 COLUMN L >

LINE 8 - 12 Represents other taxes apportioned by multiplying the total direct payroll by the applicable labor related overhead rates, i.e. Federal and State Unemployment, Federal old age pension and medical costs to accounts 107, 108, 183, and 186.

Schedule Page: 310 Line No.: 1 Column: a

Footnotes for p310-p311:

Note (1) - Canal Unit 1 Power Contract Commencing July 1, 1968.
Note (2) - Canal Unit 2 Power Contract Commencing February 1, 1967.
Note (2a)- Canal Unit 2 Power Contract Commencing May 31, 1993.
Note (3) - Seabrook Unit 1 Power Contract Commencing August 1, 1990.
Note (4) - Canal Unit 1 and 2 were sold on December 30, 1998. Amounts in columns (h) and (i) represent prior period adjustments.

(a)- Associated Companies.

(b)- Amounts in column (j), other charges, represent unbilled revenues.

Schedule Page: 310 Line No.: 6 Column: a

Same as page 310, line 1.

Schedule Page: 310 Line No.: 11 Column: a

Same as page 310, line 1, notes 1 & 4.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
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FOOTNOTE DATA

Schedule Page: 332 Line No.: 4 Column: a

(A) NON-ASSOCIATED COMPANY.
(B) VERMONT ELECTRIC TRANSMISSION LINE SUPPORT AGREEMENT, HYDRO-QUEBEC PHASE I.
(C) TERMINAL FACILITY AGREEMENT, HYDRO-QUEBEC PHASE I.
(D) SEABROOK 345 KV TRANSMISSION SUPPORT AGREEMENT.
(E) SEABROOK 345 KV TRANSMISSION FACILITIES SUPPORT AGREEMENT - TEWKSBURY LINE.
(F) HYDRO-QUEBEC PHASE II SUPPORT AGREEMENT.

Schedule Page: 340 Line No.: 1 Column: a

FOOTNOTES:

(A) INTEREST RATES ARE BASED ON THE AVERAGE BANK RATE LESS ONE-HALF THE DIFFERENCE BETWEEN THE 13-WEEK TREASURY BILL RATE AND THE AVERAGE BANK RATE.

(B) INTEREST RATES ARE ESTABLISHED DAILY BY VARIOUS BANKS.

Schedule Page: 402 Line No.: -1 Column: b

FOOTNOTES:

-1. COLUMN B. - DATA IS APPLICABLE TO CANAL ELECTRIC COMPANY'S SHARE OF SEABROOK UNIT 1 (3.52317%).

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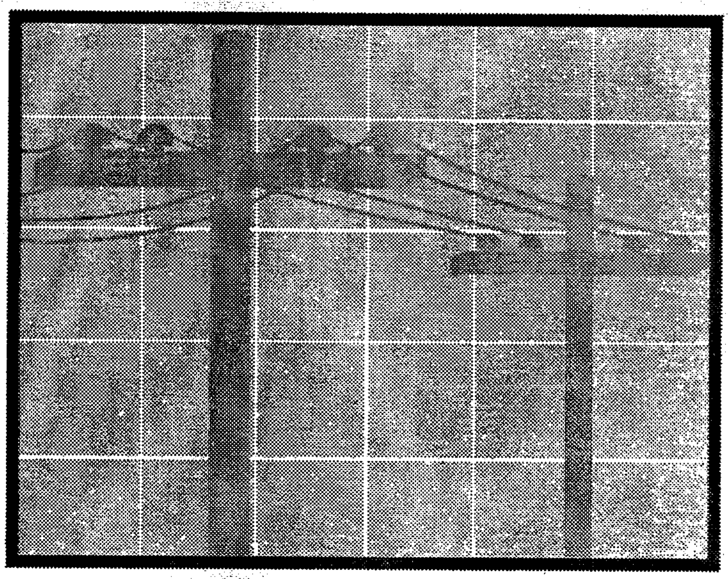
Schedule	Page No.

Schedule	Page No.



1999
Annual Report

Connecticut
Light & Power

The Northeast Utilities System

Directors

David H. Bogulawski
Vice President—
Energy Delivery

Hugh C. MacKenzie
President

Rodney O. Powell
Vice President—Central Region

Officers

Hugh C. MacKenzie
President

David H. Boguslawski
Vice President—Energy
Delivery

John B. Keane
Vice President—Generation
Divestiture

Roger C. Zaklukiewicz
Vice President—
Transmission and Distribution

Robert J. Kost
Vice President—Western
Region

Rodney O. Powell
Vice President—Central Region

Richard L. Tower
Vice President—Eastern Region

O. Kay Comendul
Secretary

Randy A. Shoop
Treasurer

John P. Stack
Controller

Debra L. Canyock
Assistant Controller—
Management Information and
Budgeting Services

Lori A. Mahler
Assistant Controller—
Accounting Services

William J. Starr
Assistant Controller—
Taxes

William J. Quinlan
Assistant Secretary

March 15, 2000

1999 Annual Report

The Connecticut Light and Power Company and Subsidiaries

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Contents

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Financial Condition

Overview

The financial improvement that began in 1998 continued throughout 1999 at The Connecticut Light and Power Company (CL&P or the company), an operating subsidiary of Northeast Utilities (NU) and part of the Northeast Utilities system (NU system), despite a rate reduction in Connecticut. CL&P's results benefited from the successful restart of the Millstone 2 nuclear unit, the strong operating performance delivered by the Millstone 3 and Seabrook Station (Seabrook) nuclear units, retail sales growth, and continued control over operation and maintenance (O&M) expenses. A rate reduction reduced the positive financial impacts of these items.

During 1999, CL&P resolved key industry restructuring issues by establishing initial stranded cost recovery levels and standard offer service tariffs and agreements. The auction of substantially all of the fossil and hydroelectric generation assets owned by CL&P and the auction of its respective interest in the output of the Millstone units, moved CL&P along in its transition into a purely electric transmission and distribution company, as contemplated by restructuring legislation in Connecticut.

CL&P lost $13.6 million in 1999, compared with a loss of $195.7 million in 1998 and a loss of $139.6 million in 1997. The 1999 results included after-tax write-offs associated with the settlement of nuclear related issues and industry restructuring totaling $28.8 million. During 1998, CL&P's results included write-offs associated with a rate decision in Connecticut and the retirement of Millstone 1 totaling $133.4 million.

In 1999, CL&P's revenues increased to $2.45 billion, up 2.5 percent from revenues of $2.39 billion in 1998. The growth was primarily due to a 2.9 percent increase in retail sales. That growth was due to weather related factors that included a hotter than normal summer. The balance of that increase was due to economic expansion in CL&P's service territory. A retail rate reduction offset some of the growth in revenues. CL&P's rates were reduced 5 percent in early 1999. CL&P's rates were further reduced in January 2000 by 5 percent. The additional 5 percent rate reduction will offset some of the growth in future revenues.

Aside from increased revenues, the primary reason for better operating performance in 1999 was the return to service from extended outages of Millstone 3 in July 1998 and Millstone 2 in May 1999.

CL&P's ability to continue improving financial performance in 2000 will depend largely on continued sales growth and on successful control of O&M expenses. CL&P also hopes to complete in 2000 the

majority of restructuring work remaining, primarily the issuance of rate reduction bonds (securitization) to lower stranded costs, and the auction of CL&P's ownership interests in the Millstone units.

Mergers

In 1998 and 1999, NU management concluded that the pace of deregulation was accelerating throughout the northeastern United States and that shareholders would benefit from NU not only remaining a major provider of electric transmission and distribution service, but also an unregulated marketer of both electricity and natural gas. NU management also concluded that as a result of the changes occurring in the highly competitive electric utility industry, increased size would be crucial to achieve its objective of being a leading provider of energy products and services in the Northeast.

On October 13, 1999, NU announced an agreement to merge with Consolidated Edison, Inc. (Con Edison), a financially stronger utility based in New York. The merger will create the nation's largest electric distribution system with more than 5 million customers and one of the 15 largest natural gas distribution systems with 1.4 million customers.

NU and Con Edison filed with various state and federal regulatory bodies in January 2000 to secure approval of the merger. The two companies expect these regulatory proceedings can be completed by the end of July 2000.

Also in 1999, NU management concluded that the NU system would be stronger and customers could be better served if NU reentered the natural gas distribution business that it had exited in 1989 and examined several potential businesses in New England. By adding gas to NU's energy mix, NU will be able to broaden its services to its existing customers and will have additional opportunities for long-term growth. In June 1999, NU announced an agreement to merge with Yankee Energy System, Inc. (Yankee). The merger will return to NU Connecticut's largest natural gas distribution system, as well as several unregulated businesses involved in energy services, collections and other areas. The Yankee merger received Yankee shareholder approval in October 1999, final Connecticut Department of Public Utility Control (DPUC) approval in December 1999 and Securities and Exchange Commission (SEC) approval in January 2000. The merger closed on March 1, 2000.

Liquidity

During 1999, strong sales growth, improved nuclear performance and continued control of O&M expenses resulted in net cash flows provided by operations of $299.4 million in 1999, compared to $364.1 million in 1998 and $37.2 million in 1997. The decrease in cash flows from operations is primarily related to increased tax payments in 1999.

On December 15, 1999, CL&P sold 2,235 megawatts (MW) of fossil generation assets to an unaffiliated company. Proceeds from the sale totaled $516.9 million, including payments for fuel and inventory.

CL&P used the proceeds primarily to par call $406 million of first mortgage bonds in December 1999. CL&P also used $57.5 million to buy out its lease of four 40 MW turbines.

Proceeds from the generation asset sale are included in net cash flows provided by investing activities. Including construction expenditures and investments in nuclear decommissioning trusts, net cash flows provided by investing activities were $261.4 million in 1999, compared with net cash flows used in investing activities of $183 million in 1998 and $108.1 million in 1997.

Positive operating cash flows and the proceeds from the generation asset sale enabled CL&P to substantially reduce its outstanding debt. As of December 31, 1999, CL&P's total debt level, including capital lease obligations, was $1.6 billion, compared with $2.2 billion as of December 31, 1998, and $2.3 billion as of December 31, 1997.

The net cash flows used in financing activities were $560.9 million in 1999, compared to $181.2 million in 1998 and net cash flows provided by financing activities of $71 million in 1997. This included $639.8 million paid in 1999 to retire long-term debt and preferred stock, compared to $80.7 million in 1998 and $204.1 million in 1997. There were no cash dividends on common shares paid in 1999 and 1998 and $6 million in 1997. Payments made for preferred stock dividends were $12.8 million, $14.1 million and $15.2 million for 1999, 1998 and 1997, respectively.

CL&P's access to capital also benefited from the strong operating performance at Millstone 2 and 3 and the announced merger with Con Edison. During 1999, CL&P's securities received several upgrades from three credit rating agencies. CL&P's senior secured bonds achieved investment grade ratings for the first time since early 1997. At year end, all securities were under review for possible upgrades, or on "credit watch" with positive implications by Standard & Poor's, Moody's Investors Service and Fitch IBCA.

The rating agency upgrades benefited CL&P's efforts to broaden its credit lines. On November 19, 1999, CL&P and Western Massachusetts Electric Company (WMECO) entered into a new 364-day revolving credit facility for $500 million, replacing the previous $313.75 million facility which was to expire on November 21, 1999. The revolving credit facility, which is secured by second mortgages on Millstone 2 and 3, will be used to bridge gaps in working capital and provide short-term liquidity. CL&P may draw up to $300 million under the facility. Once CL&P receives the proceeds from securitization, the $500 million facility will be reduced to $300 million, with a $200 million limit for CL&P. As of December 31, 1999, CL&P had $90 million outstanding under this facility.

For further information regarding the CL&P and WMECO revolving credit facility, see Note 3, "Short-Term Debt," to the consolidated financial statements.

CL&P also has arranged financing through the sale of its accounts receivable. CL&P can finance up to $200 million through this

facility. As of December 31, 1999, CL&P had $170 million outstanding under this facility.

During 2000, CL&P hopes to receive regulatory approval to begin the process of securitizing its approved stranded costs. Securitization involves issuing rate reduction bonds with interest rates lower than the company's weighted average cost of capital. Proceeds from securitization will be used to significantly reduce the capitalization of CL&P and buyout or buydown certain purchased-power contracts with a number of nonutility generators.

Restructuring

During 1999, Connecticut made significant progress in resolving industry restructuring issues. Restructuring orders issued in Connecticut allowed CL&P to determine the impacts of discontinuing Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," for the generation portion of CL&P's business. The transmission and distribution portion of that business will continue to be cost-of-service regulated. In addition, the restructuring orders provided for a transition charge which allows for the recovery of CL&P's generation-related regulatory assets and prudently incurred stranded costs.

During April 1999, CL&P filed its standard offer service plan with the DPUC and received a decision on October 1, 1999, as amended on December 15, 1999. In that decision, the DPUC approved the recovery of CL&P's regulatory assets and certain stranded costs associated with CL&P's nuclear generation assets and established the methodology for setting CL&P's standard offer rates, including the transition charge and transmission and distribution rates. The DPUC ruled on CL&P's stranded cost filing in July 1999 approving $3.5 billion of stranded cost recovery, which is utilized, in part, in the determination of the transition charge.

As provided for in the electric utility restructuring legislation enacted in April 1998, 35 percent of CL&P's customers were able to choose their electric generation supplier on January 1, 2000, with the remaining 65 percent having choice on July 1, 2000. The major components of rates are a transmission and distribution charge, a generation charge and a transition charge. For those customers who do not or are unable to choose another competitive electric generation supplier, CL&P will supply standard offer or generation service at an average rate of $0.04813 per kilowatt-hour (kWh) through December 31, 2003. The revenues attributable to standard offer (generation) service are expected to exceed the actual cost of providing generation and the difference will be applied against stranded costs. In accordance with a plan approved by the DPUC, one-half of the CL&P standard offer load was procured through a competitive bidding process, with the remaining one-half of the power being supplied by an affiliated company. The contracts are in place through the end of 2003. For further information regarding commitments and contingencies related to the Connecticut restructuring order, see Note 11A, "Commitments and Contingencies - Restructuring," to the consolidated financial statements.

Generation Asset Divestitures

The Connecticut restructuring laws required CL&P to divest of its generation assets and utilize substantially all of the net gains from any sales to offset stranded costs. During 1999, CL&P sold its fossil generation assets resulting in a net gain of $286.5 million. A corresponding amount of regulatory assets was amortized. Also during 1999, CL&P signed agreements to transfer certain hydroelectric generation assets to Northeast Generation Company, an unregulated affiliate of NU. This transaction closed on March 14, 2000. In September 1999, NU announced that the Millstone nuclear generation assets of its subsidiaries, CL&P and WMECO, will be put up for auction as soon as practical. For further information regarding commitments and contingencies related to the generation asset divestitures, see Note 11A, "Commitments and Contingencies - Restructuring," to the consolidated financial statements.

Nuclear Generation

Millstone Nuclear Units

Millstone 3 received the appropriate Nuclear Regulatory Commission (NRC) approvals and resumed operation in July 1998. Millstone 2 received similar NRC approvals, resumed operation and was returned to CL&P's rate base in May 1999. Millstone 3 and 2 achieved annual capacity factors of 81.7 percent and 57.9 percent in 1999, respectively. After a 60-day refueling and maintenance outage, Millstone 3 returned to service on June 29, 1999, and has achieved a 98.1 percent capacity factor through December 31, 1999. Since returning to service in May 1999, Millstone 2 has achieved a 90.3 percent capacity factor through December 31, 1999. NU's total share of O&M expenses associated with Millstone 3 and 2 totaled $261.8 million in 1999, as compared to $323.2 million in 1998 and $406 million in 1997. Millstone 1 is currently in decommissioning status.

An auction of CL&P's ownership interests in the Millstone units is expected in 2000 with a closing in 2001. Based on regulatory decisions received in 1999, management expects to recover all of its remaining nuclear stranded costs from retail customers.

Seabrook

Seabrook achieved an annual capacity factor of 86.4 percent in 1999. However, since returning to service on May 13, 1999, after a 48-day refueling and maintenance outage, Seabrook has achieved a 99 percent capacity factor through December 31, 1999.

CL&P anticipates auctioning its 4.06 percent share of Seabrook, with the 35.98 percent share owned by its affiliate North Atlantic Energy Corporation.

Yankee Companies

On June 1, 1999, the Federal Energy Regulatory Commission accepted the offer of settlement which was filed on January 15, 1999, by the Maine Yankee Atomic Power Company (MYAPC). The significant aspects of the settlement allowed MYAPC to collect $33.1 million annually to pay for

decommissioning and spent fuel, approved its return on equity of 6.5 percent, permitted full recovery of MYAPC's unamortized investment, including fuel, and set an incentive budget for decommissioning at $436.3 million.

On October 15, 1999, the Vermont Yankee Nuclear Power Corporation (VYNPC) agreed to sell its unit for $22 million to an unaffiliated company. Among other commitments, the acquiring company agreed to assume the decommissioning cost of the unit after it is taken out of service, and the VYNPC owners have agreed to fund the uncollected decommissioning cost to a negotiated amount at the time of the closing of the sale. VYNPC's owners have also agreed either to enter into a new purchased-power agreement with the acquiring company or to buy out such future power payment obligations by making a fixed payment to them. CL&P has elected the buyout option. The VYNPC owners' obligations to close and pay such amounts are conditioned upon their receipt of satisfactory regulatory approval of the transaction, including provision for adequate recovery of these payments.

Nuclear Decommissioning

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear units in their financial statements.

Currently, the Financial Accounting Standards Board plans to review the accounting for obligations associated with the retirement of long-lived assets, including the decommissioning of nuclear units. If current accounting practices for nuclear decommissioning change, the annual provision for decommissioning could increase relative to 1999, and the estimated cost for decommissioning could be recorded as a liability with recognition of an increase in the cost of the related nuclear unit. However, management does not believe that such a change will have a material impact on CL&P's financial statements due to its current and future ability to recover decommissioning costs through rates.

Spent Nuclear Fuel Disposal Costs

The United States Department of Energy (DOE) originally was scheduled to begin accepting delivery of spent fuel in 1998. However, delays in confirming the suitability of a permanent storage site continually have postponed plans for the DOE's long-term storage and disposal site. Extended delays or a default by the DOE could lead to consideration of costly alternatives. CL&P has the primary responsibility for the interim storage of its share of spent nuclear fuel. Adequate storage capacity exists to accommodate all spent nuclear fuel at Millstone 1. The facilities for Millstone 2 are expected to provide adequate storage to accommodate a full-core discharge from the reactor until 2005 with the implementation of currently planned modifications. Fuel consolidation, which has been licensed for Millstone 2, could provide adequate storage capacity for its projected life. The facilities for Millstone 3 are expected to provide adequate storage for its projected life with the addition of new storage racks. Seabrook is expected to have spent fuel storage capacity until at least 2010. Meeting spent fuel storage requirements

beyond these periods could require new and separate storage facilities. For further information regarding spent nuclear fuel disposal costs, see Note 11D, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

Market Risk and Risk Management Instruments

CL&P uses energy price risk management instruments to manage the market risk exposures associated with changes in energy prices. CL&P uses these instruments to reduce risk by essentially creating offsetting market exposures. Based on the derivative instruments that were being utilized by CL&P to hedge some of their energy price risks, there may be an impact on earnings upon adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which management has not estimated at this time.

Energy Price Risk Management Instruments

In the generation of electricity, the most significant segment of the variable cost component is the cost of fuel. Typically, most of CL&P's fuel purchases were protected by a regulatory fuel price adjustment clause. However, for a specific, well-defined volume of fuel that was excluded from the energy price adjustment clause, CL&P employed energy price risk management instruments to protect itself against the risk of rising fuel prices, thereby limiting fuel costs and protecting its profit margins. These risks were created by the sale of long-term fixed-price electricity sales contracts to wholesale customers.

In 1999, CL&P divested substantially all of its fossil and hydroelectric generation assets and also transferred the rights and obligations of its long-term fixed-price contracts to an unregulated affiliate. As a result, the fuel swap positions were marked-to-market and CL&P recognized a loss of $5.2 million. In January 2000, the fuel swap positions were liquidated.

Other Matters

Environmental Matters

CL&P is subject to environmental laws and regulations structured to mitigate or remove the effect of past operations and to improve or maintain the quality of the environment. For further information regarding environmental matters, see Note 11C, "Commitments and Contingencies - Environmental Matters," to the consolidated financial statements.

Other Commitments and Contingencies

CL&P is subject to other commitments and contingencies primarily relating to nuclear litigation, nuclear insurance contingencies, its construction program, long-term contractual arrangements, and the New England Power Pool generation pricing. For further information regarding these commitments and contingencies, see Note 11, "Commitments and Contingencies," to the consolidated financial statements.

Year 2000 Issues

The transition into the year 2000 was a success for the NU system and CL&P. Its mission to provide safe, reliable energy to its customers and to ensure continued operability of critical business functions was not affected by any year 2000 related issues.

The projected total cost of the year 2000 program is estimated at $21 million for the NU system. The total cost to date was funded through operating cash flows. The NU system has incurred and expensed $20 million related to year 2000 readiness efforts.

Forward Looking Statements

This discussion and analysis includes forward looking statements, which are statements of future expectations and not facts. Words such as *estimates, expects, anticipates, intends, plans,* and similar expressions identify forward looking statements. Actual results or outcomes could differ materially as a result of further actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in historical weather patterns, changes in laws, developments in legal or public policy doctrines, technological developments, and other presently unknown or unforeseen factors.

RESULTS OF OPERATIONS

The components of significant income statement variances for the past two years are provided in the table below.

	Income Statement Variances (Millions of Dollars)			
	1999 over/(under) 1998		1998 over/(under) 1997	
	Amount	Percent	Amount	Percent
Operating Revenues	$66	3%	$(79)	(3)%
Operating Expenses:				
Fuel, purchased and net interchange power	(143)	(13)	(60)	(5)
Other operation and maintenance	(94)	(12)	(136)	(15)
Depreciation	(23)	(10)	(22)	(9)
Amortization of regulatory assets, net	327	(a)	59	96
Federal and state income taxes	164	-	(12)	(18)
Taxes other than income taxes	5	3	(2)	(1)
Gain on sale of utility plant	(286)	-	-	-
Operating income	146	(a)	36	(a)
Equity in earnings of regional nuclear generating companies	(5)	(76)	1	10
Nuclear unrecoverable costs	90	63	(143)	-
Other, net	(20)	(a)	(4)	(a)
Minority interest in loss of subsidiary	-	-	-	-
Interest charges, net	-	-	5	3
Net Income/(Loss)	182	93	(56)	(40)

(a) Percentage greater than 100.

Operating Revenues
Operating revenues increased by $66 million or 3 percent in 1999, due to higher wholesale revenues ($72 million). The wholesale revenue increase is primarily due to higher energy sales and related capacity and transmission revenues. Retail revenues decreased primarily due to a retail rate reduction ($55 million) and lower fuel clause revenues ($33 million), partially offset by the impact of Millstone 2 and 3 being returned to CL&P's rate base ($13 million) and higher retail sales ($62 million). Retail kilowatt-hour sales increased by 2.9 percent.

The removal of Millstone 2 and 3 from CL&P's rate base reduced revenues by $68 million in 1998. Wholesale revenues decreased by $33 million, primarily as a result of terminating the contract with the Connecticut Municipal Electric Energy Cooperative (CMEEC). These decreases were partially offset by higher retail sales volumes. Retail kilowatt-hour sales were 2.2 percent higher and contributed $36 million to nonfuel revenues in 1998 primarily as a result of economic growth.

Fuel, Purchased and Net Interchange Power
Fuel, purchased and net interchange power expense decreased in 1999, primarily due to lower replacement power costs due to the return to service of Millstone 2 and 3, partially offset by higher purchased-power costs as a result of a high sales demand.

The change in fuel, purchased and net interchange power expense in 1998, is primarily due to lower replacement power costs due to the return to service of Millstone 3 and lower costs at the Yankee nuclear units ($21 million). This change was partially offset by higher capacity charges ($51 million).

Other Operation and Maintenance
Other O&M expenses decreased in 1999, primarily due to lower costs at the Millstone units ($107 million), lower conservation and load management amortization ($14 million), and lower fossil O&M expenses ($7 million), partially offset by the recognition of environmental insurance proceeds in 1998 ($9 million), higher transmission expenses ($12 million), and higher storm costs ($12 million).

Other O&M expenses decreased in 1998, primarily due to lower costs at the Millstone units ($125 million), lower administrative and general expenses ($12 million), the recognition of environmental insurance proceeds ($9 million), lower distribution costs ($8 million), a decrease in sales and marketing expenses ($8 million), and lower costs from ISO-New England for interchange services ($7 million). These decreases were partially offset by higher recognition of nuclear refueling outage costs primarily as a result of the 1996 rate settlement ($34 million).

Depreciation
Depreciation decreased in 1999 and 1998, primarily due to the retirement of Millstone 1.

Amortization of Regulatory Assets, Net

Amortization of regulatory assets, net increased in 1999, primarily due to the increased amortization associated with the gain on the sale of fossil generation assets ($286 million), the amortization of CL&P's Millstone 1 remaining investment ($51 million) and the reclassification of the depreciation on the nuclear plants transferred to regulatory assets ($19 million). These increases were partially offset by the completion of the amortization of the cogeneration deferral in the first quarter of 1999 ($23 million).

Amortization of regulatory assets, net increased in 1998, primarily due to accelerated amortizations in accordance with regulatory decisions ($52 million) and the beginning of the amortization of the Millstone 1 investment ($20 million).

Federal and State Income Taxes

Federal and state income taxes increased in 1999, primarily due to higher book taxable income.

Federal and state income taxes decreased in 1998, primarily due to lower book taxable income and the increase in income tax credits primarily due to the Millstone 1 write-off of unrecoverable costs as a result of the February 1999 rate decision.

Gain on Sale of Utility Plant

CL&P recorded a gain on the sale of its fossil generation assets in 1999. A corresponding amount of amortization expense was recorded.

Equity Earnings of Regional Nuclear Generating Companies

Equity earnings of regional nuclear generating companies decreased in 1999, primarily due to lower earnings from the Connecticut Yankee Atomic Power Company.

The change in equity earnings of regional nuclear generating companies in 1998 was not significant.

Nuclear Unrecoverable Costs

Nuclear unrecoverable costs in 1999 are comprised of one-time charges related to the write-off of capital projects as a result of the Connecticut standard offer decision ($11 million), the settlement of Millstone 3 joint owner litigation, net of insurance proceeds ($22 million) and the write-off of CMEEC nuclear costs ($20 million). In comparison, 1998 is comprised of the write-off of the Millstone 1 entitlement formerly held by CMEEC ($27.8 million) and the write-off of unrecoverable costs as a result of the February 1999 rate decision ($115.3 million).

Other, Net

Other, net, decreased in 1999, primarily due to the loss on the CL&P assignment of market-based contracts to Select Energy, Inc.

The change in other, net in 1998 was not significant.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors
of The Connecticut Light and Power Company:

We have audited the accompanying consolidated balance sheets of The Connecticut Light and Power Company (a Connecticut corporation and a wholly owned subsidiary of Northeast Utilities) and subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, comprehensive income, common stockholder's equity and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of The Connecticut Light and Power Company and subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with generally accepted accounting principles.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Hartford, Connecticut
January 25, 2000

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31,	1999	1998	1997
	(Thousands of Dollars)		
Operating Revenues	$2,452,855	$2,386,864	$2,465,587
Operating Expenses:			
Operation -			
Fuel, purchased and net interchange power	927,989	1,070,677	1,131,063
Other	480,138	520,518	572,900
Maintenance	217,961	271,317	355,772
Depreciation	193,776	216,509	238,667
Amortization of regulatory assets, net	447,776	120,884	61,648
Federal and state income taxes	122,059	(11,642)	(59,436)
Taxes other than income taxes	174,884	170,347	172,592
Gain on sale of utility plant	(286,477)	-	-
Total operating expenses	2,278,106	2,358,610	2,473,206
Operating Income/(Loss)	174,749	28,254	(7,619)
Other (Loss)/Income:			
Equity in earnings of regional nuclear generating companies	1,506	6,241	5,672
Nuclear unrecoverable costs	(53,031)	(143,239)	-
Other, net	(25,962)	(6,075)	(1,856)
Minority interest in loss of subsidiary	(9,300)	(9,300)	(9,300)
Income taxes	36,921	67,127	7,573
Other (loss)/income, net	(49,866)	(85,246)	2,089
Income/(Loss) before interest charges	124,883	(56,992)	(5,530)
Interest Charges:			
Interest on long-term debt	127,533	133,192	132,127
Other interest	10,918	5,541	1,940
Interest charges, net	138,451	138,733	134,067
Net Loss	$ (13,568)	$ (195,725)	$ (139,597)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Net Loss	$ (13,568)	$ (195,725)	$ (139,597)
Other comprehensive income, net of tax:			
Unrealized gains on securities	38	638	-
Minimum pension liability adjustments	-	(260)	-
Other comprehensive income, net of tax	38	378	-
Comprehensive Loss	$ (13,530)	$ (195,347)	$ (139,597)

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AT DECEMBER 31,	1999	1998
	(Thousands of Dollars)	
ASSETS		
Utility Plant, at original cost:		
Electric	$ 5,811,126	$ 6,173,871
Less: Accumulated provision for depreciation	4,234,771	2,758,012
	1,576,355	3,415,859
Construction work in progress	115,529	83,477
Nuclear fuel, net	80,766	87,867
Total net utility plant	1,772,650	3,587,203
Other Property and Investments:		
Nuclear decommissioning trusts, at market	516,796	452,755
Investments in regional nuclear generating companies, at equity	54,472	56,999
Other, at cost	36,696	93,864
	607,964	603,618
Current Assets:		
Cash	364	434
Investments in securitizable assets	107,620	160,253
Notes receivable from affiliated companies	-	6,600
Receivables, less accumulated provision for uncollectible accounts of $300 in 1999 and 1998	19,680	22,186
Accounts receivable from affiliated companies	3,390	1,721
Taxes receivable	-	26,478
Fuel, materials, and supplies, at average cost	37,603	71,982
Prepayments and other	148,628	121,514
	317,285	411,168
Deferred Charges:		
Regulatory assets	2,564,095	1,415,838
Unamortized debt expense	16,323	19,603
Other	19,967	12,768
	2,600,385	1,448,209
Total Assets	$ 5,298,284	$ 6,050,198

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AT DECEMBER 31,	1999	1998
	(Thousands of Dollars)	
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $10 par value - authorized 24,500,000 shares; 12,222,930 shares outstanding in 1999 and 1998	$ 122,229	$ 122,229
Capital surplus, paid in	665,598	664,156
Retained earnings	153,254	210,108
Accumulated other comprehensive income	416	378
Total common stockholder's equity	941,497	996,871
Preferred stock not subject to mandatory redemption	116,200	116,200
Preferred stock subject to mandatory redemption	79,789	99,539
Long-term debt	1,241,051	1,793,952
Total capitalization	2,378,537	3,006,562
Minority Interest in Consolidated Subsidiary	100,000	100,000
Obligations Under Capital Leases	50,969	68,444
Current Liabilities:		
Notes payable to banks	90,000	10,000
Notes payable to affiliated company	11,700	-
Long-term debt and preferred stock - current portion	178,755	233,755
Obligations under capital leases - current portion	93,431	94,440
Accounts payable	101,106	121,040
Accounts payable to affiliated companies	3,215	32,758
Accrued taxes	169,214	19,396
Accrued interest	18,640	31,409
Other	26,347	34,872
	692,408	577,670
Deferred Credits and Other Long-term Liabilities:		
Accumulated deferred income taxes	999,473	1,194,722
Accumulated deferred investment tax credits	107,064	114,457
Decommissioning obligation - Millstone 1	580,320	560,500
Deferred contractual obligations	238,142	277,826
Other	151,371	150,017
	2,076,370	2,297,522
Total Capitalization and Liabilities	$ 5,298,284	$ 6,050,198

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock	Capital Surplus, Paid In	Retained Earnings (a)	Accumulated Other Comprehensive Income	Total
	(Thousands of Dollars)				
Balance at January 1, 1997	$122,229	$639,657	$ 580,779	$ -	$1,342,665
Net loss for 1997			(139,597)		(139,597)
Cash dividends on preferred stock			(15,221)		(15,221)
Cash dividends on common stock			(5,989)		(5,989)
Capital stock expenses, net		1,676			1,676
Balance at December 31, 1997	122,229	641,333	419,972	-	1,183,534
Net loss for 1998			(195,725)		(195,725)
Cash dividends on preferred stock			(14,139)		(14,139)
Capital stock expenses, net		2,764			2,764
Capital contribution from Northeast Utilities		20,000			20,000
Gain on repurchase of preferred stock		59			59
Other comprehensive income				378	378
Balance at December 31, 1998	122,229	664,156	210,108	378	996,871
Net loss for 1999			(13,568)		(13,568)
Cash dividends on preferred stock			(12,832)		(12,832)
Capital stock expenses, net		1,442			1,442
Allocation of benefits - ESOP			(30,454)		(30,454)
Other comprehensive income				38	38
Balance at December 31, 1999	$122,229	$665,598	$ 153,254	$ 416	$ 941,497

(a) The company has dividend restrictions imposed by its long-term debt agreements. At December 31, 1999, these restrictions totaled approximately $512 million.

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

THE CONNECTICUT LIGHT AND POWER COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 1999	1998	1997
Operating Activities:			
Net loss	$ (13,568)	$(195,725)	$(139,597)
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation	193,776	216,509	238,667
Deferred income taxes and investment tax credits, net	(140,459)	(65,689)	(10,401)
Amortization of regulatory assets, net	447,776	120,884	61,648
Amortization of demand-side-management costs, net	10,014	42,085	38,029
Amortization/(deferral) of recoverable energy costs	12,702	30,745	(9,533)
Deferred nuclear refueling outage, net of amortization	-	-	(45,333)
Nuclear unrecoverable costs	53,031	143,239	-
Allocation of ESOP benefits	(30,454)	-	-
Gain on sale of utility plant	(286,477)	-	-
Net other (uses)/sources of cash	(113,174)	34,016	(50,953)
Changes in working capital:			
Receivables	837	29,914	254,223
Fuel, materials and supplies	34,379	9,896	(1,941)
Accounts payable	(49,477)	(63,592)	(22,036)
Accrued taxes	149,818	(13,621)	4,310
Investments in securitizable assets	52,633	45,372	(205,625)
Other working capital (excludes cash)	(21,930)	30,097	(74,266)
Net cash flows provided by operating activities	299,427	364,130	37,192
Financing Activities:			
Issuance of long-term debt	-	-	200,000
Net increase/(decrease) in short-term debt	91,700	(86,300)	96,300
Reacquisitions and retirements of long-term debt	(620,010)	(45,006)	(204,116)
Reacquisitions and retirements of preferred stock	(19,750)	(35,711)	-
Cash dividends on preferred stock	(12,832)	(14,139)	(15,221)
Cash dividends on common stock	-	-	(5,989)
Net cash flows (used in)/provided by financing activities	(560,892)	(181,156)	70,974
Investing Activities:			
Investment in plant:			
Electric utility plant	(180,982)	(132,194)	(155,550)
Nuclear fuel	(26,198)	(8,444)	(702)
Net cash flows used for investments in plant	(207,180)	(140,638)	(156,252)
Investment in NU system Money Pool	6,600	(6,600)	109,050
Investment in nuclear decommissioning trusts	(54,582)	(54,106)	(45,314)
Other investment activities, net	(355)	(1,655)	(15,595)
Net proceeds from the sale of utility plant	516,912	-	-
Capital contributions from Northeast Utilities	-	20,000	-
Net cash flows provided by/(used in) investing activities	261,395	(182,999)	(108,111)
Net (decrease)/increase in cash for the period	(70)	(25)	55
Cash - beginning of period	434	459	404
Cash - end of period	$ 364	$ 434	$ 459
Supplemental Cash Flow Information:			
Cash paid/(refunded) during the year for:			
Interest, net of amounts capitalized	$ 142,398	$ 110,119	$ 145,962
Income taxes	$ 19,754	$ (46,747)	$ (22,338)
Increase in obligations:			
Niantic Bay Fuel Trust	$ 4,752	$ 10,208	$ 2,815

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About The Connecticut Light and Power Company

The Connecticut Light and Power Company (CL&P or the company) along with the Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO), North Atlantic Energy Corporation (NAEC), and Holyoke Water Power Company (HWP) are the operating companies comprising the Northeast Utilities system (NU system) and are wholly owned by Northeast Utilities (NU). The NU system serves in excess of 30 percent of New England's electric needs and is one of the 20 largest electric utility systems in the country as measured by revenues. The NU system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through CL&P, PSNH and WMECO. NAEC sells all of its entitlement to the capacity and output of the Seabrook Station (Seabrook) nuclear unit to PSNH under the terms of two life-of-unit, full cost recovery contracts. HWP, also is engaged in the production and distribution of electric power.

NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) and the NU system, including CL&P, is subject to provisions of the 1935 Act. Arrangements among the NU system companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the Federal Energy Regulatory Commission (FERC) and/or the SEC. CL&P is subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions.

Several wholly owned subsidiaries of NU provide support services for the NU system companies, including CL&P, and, in some cases, for other New England utilities. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, information resources, engineering, financial, legal, operational, planning, purchasing, and other services to the NU system companies, including CL&P. Northeast Nuclear Energy Company acts as agent for the NU system companies and other New England utilities in operating the Millstone nuclear units. North Atlantic Energy Service Corporation has operational responsibility for Seabrook. In addition, CL&P has established a special purpose subsidiary whose business consists of the purchase and resale of receivables.

On October 13, 1999, NU and Consolidated Edison, Inc. (Con Edison) announced that they have agreed to a merger to combine the two companies. For further information, see Note 17, "Merger Agreement with Con Edison."

B. Presentation

The consolidated financial statements of CL&P include the accounts of all subsidiaries. Intercompany transactions have been eliminated in consolidation.

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

Certain reclassifications of prior years' data have been made to conform with the current year's presentation.

All transactions among affiliated companies are on a recovery of cost basis which may include amounts representing a return on equity and are subject to approval by various federal and state regulatory agencies.

C. New Accounting Standards

The Financial Accounting Standards Board (FASB) has issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 establishes accounting and reporting standards for derivative instruments and hedging activities. This statement will require derivative instruments utilized by CL&P to be recognized as assets or liabilities at fair value.

In June 1999, the FASB delayed the adoption date of SFAS No. 133 to January 1, 2001.

Based on the derivative instruments utilized by CL&P, there may be an impact on earnings upon adoption of SFAS No. 133 which management has not estimated at this time.

D. Investments and Jointly Owned Electric Utility Plant

Regional Nuclear Generating Companies: CL&P owns common stock in four regional nuclear companies (Yankee Companies). CL&P's ownership interests in the Yankee Companies at December 31, 1999 and 1998, which are accounted for on the equity basis due to CL&P's ability to exercise significant influence over their operating and financial policies are 34.5 percent of the Connecticut Yankee Atomic Power Company (CYAPC), 24.5 percent of the Yankee Atomic Electric Company (YAEC), 12 percent of the Maine Yankee Atomic Power Company (MYAPC), and 9.5 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC). CL&P's total equity investment in the Yankee Companies at December 31, 1999 and 1998, is $54.5 million and $57.0 million, respectively. Each Yankee Company owns a single nuclear generating unit. However, VYNPC is the only unit still in operation at December 31, 1999.

Millstone: CL&P has an 81 percent joint ownership interest in both Millstone 1, a 660 megawatt (MW) nuclear unit and Millstone 2, an 870 MW nuclear generating unit. CL&P has a 52.93 percent joint ownership interest in Millstone 3, a 1,154 MW nuclear generating unit. NU expects to auction all three units as a single package in 2000, with a closing in 2001. Appropriate regulatory approvals will be required to complete the auction.

Seabrook: CL&P has a 4.06 percent joint ownership interest in Seabrook, a 1,148 MW nuclear generating unit. CL&P expects to auction its investment in Seabrook, jointly with NAEC, upon the resolution of the restructuring issues in the state of New Hampshire.

Plant-in-service and the accumulated provision for depreciation for CL&P's share of Millstone 2 and 3 and Seabrook are as follows:

At December 31,	1999	1998
	(Millions of Dollars)	
Plant-in-service		
Millstone 2	$ 771.7	$ 759.3
Millstone 3	1,915.1	1,909.4
Seabrook	173.9	174.3
Accumulated provision for depreciation		
Millstone 2	$ 743.3	$ 309.2
Millstone 3	1,822.8	609.3
Seabrook	165.7	39.3

E. Depreciation

The provision for depreciation is calculated using the straight-line method based on estimated remaining useful lives of depreciable utility plant-in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency, where applicable. Except for major facilities, depreciation rates are applied to the average plant-in-service during the period. Major facilities are depreciated from the time they are placed in service. When plant is retired from service, the original cost of the plant, including costs of removal less salvage, is charged to the accumulated provision for depreciation. The costs of closure and removal of nonnuclear facilities are accrued over the life of the plant as a component of depreciation. The depreciation rates for the several classes of electric plant-in-service are equivalent to a composite rate of 3.3 percent in 1999, 3.2 percent in 1998 and 3.8 percent in 1997.

At December 31, 1999 and 1998, the accumulated provision for depreciation included $47.9 million accrued for the cost of removal, net of salvage, for nonnuclear generation property.

As a result of discontinuing the application of SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation," for CL&P's generation business, including CL&P's ownership interest in Seabrook, the company recorded a charge to accumulated depreciation for the nuclear plant in excess of fair market value in the amount of $1.7 billion, and a corresponding regulatory asset was created.

F. Revenues

Revenues are based on authorized rates applied to each customer's use of electricity. In general, rates can be changed only through a formal proceeding before the appropriate regulatory commission. Regulatory commissions also have authority over the terms and conditions of nontraditional rate-making arrangements. At the end of each accounting period, CL&P accrues a revenue estimate for the amount of energy delivered but unbilled.

G. Regulatory Accounting and Assets

The accounting policies of CL&P and the accompanying consolidated financial statements conform to generally accepted accounting principles applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71. As a result of final restructuring orders issued in 1999, CL&P discontinued the application of SFAS No. 71 for the generation portion of its business.

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management continues to believe it is probable that CL&P will recover its investments in long-lived assets, including regulatory assets. In addition, all material regulatory assets are earning a return. The components of CL&P's regulatory assets are as follows:

At December 31,	1999	1998
	(Millions of Dollars)	
Recoverable nuclear costs	$1,781.9	$ 442.7
Income taxes, net	399.5	538.5
Unrecovered contractual obligations	228.9	267.0
Recoverable energy costs, net	89.4	102.1
Other	64.4	65.5
	$2,564.1	$1,415.8

The restructuring orders in Connecticut provide for the transmission and distribution business to continue to be cost-of-service based and also provide for a transition charge which recovers stranded costs, including the nuclear regulatory assets established below.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As a result of discontinuing the application of SFAS No. 71 for CL&P's generation business, the company reclassified nuclear plant in excess of its estimated fair market value from plant to regulatory assets. As of December 31, 1999, the unamortized balance of $1.38 billion is classified as recoverable nuclear costs. Also included in that regulatory asset component for 1999 is $401.9 million, which includes Millstone 1 recoverable nuclear costs relating to the recoverable portion of the undepreciated plant and related assets ($101.9 million) and the decommissioning and closure obligation ($300 million).

H. Income Taxes

The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions.

The tax effect of temporary differences, including timing differences accrued under previously approved accounting standards, that give rise to the accumulated deferred tax obligation is as follows:

At December 31,	1999	1998
	(Millions of Dollars)	
Accelerated depreciation and other plant-related differences	$845.6	$1,002.7
Net operating loss carryforwards	-	(7.8)
Regulatory assets - income tax gross up	153.7	279.8
Other	0.2	(80.0)
	$999.5	$1,194.7

I. Recoverable Energy Costs

Under the Energy Policy Act of 1992 (Energy Act), CL&P is assessed for its proportionate share of the costs of decontaminating and decommissioning uranium enrichment plants owned by the United States Department of Energy (DOE) (D&D Assessment). The Energy Act requires that regulators treat D&D Assessments as a reasonable and necessary current cost of fuel, to be fully recovered in rates like any other fuel cost. CL&P is currently recovering these costs through rates. As of December 31, 1999 and 1998, CL&P's total D&D Assessment deferrals were $26.9 million and $44.9 million, respectively.

Through December 31, 1999, CL&P had an energy adjustment clause under which fuel prices above or below base-rate levels were charged to or credited to customers. At December 31, 1999 and 1998, recoverable energy costs included $62.6 million and $78.1 million, respectively, of costs previously deferred. Coincident with the start of restructuring, the fuel clause was terminated. The balance at December 31, 1999, has been recorded as a generation-related stranded cost and will be recovered through a transition charge mechanism.

J. Unrecovered Contractual Obligations

Under the terms of contracts with the Yankee Companies, the shareholder-sponsored companies, including CL&P, are responsible for their proportionate share of the remaining costs of the units, including decommissioning. As management expects that CL&P will be allowed to recover these costs from its customers, CL&P has recorded a regulatory asset, with a corresponding obligation, on its balance sheet.

2. NUCLEAR DECOMMISSIONING AND PLANT CLOSURE COSTS

Millstone and Seabrook: CL&P's operating nuclear power plants, Millstone 2 and 3 and Seabrook, have service lives that are expected to end during the years 2015 through 2026 and upon retirement, must be decommissioned. Millstone 1's expected service life was to end in 2010, however, in July 1998, restart activities were discontinued and preparations for decommissioning the unit began. Current decommissioning studies conclude that complete and immediate dismantlement as soon as practical after retirement continues to be the most viable and economic method of decommissioning a unit. These studies are reviewed and updated periodically to reflect changes in decommissioning requirements, costs, technology, and inflation. Changes in requirements or technology, the timing of funding or dismantling or adoption of a decommissioning method other than immediate dismantlement would change decommissioning cost estimates and the amounts required to be recovered. CL&P attempts to recover sufficient amounts through its allowed rates to cover its expected decommissioning costs.

CL&P's ownership share of the estimated cost of decommissioning Millstone 2 and 3 and Seabrook, in year end 1999 dollars, is $334.9 million, $327.9 million and $22.9 million, respectively. Nuclear decommissioning costs are accrued over the expected service lives of the units and are included in depreciation expense. Nuclear decommissioning expenses for these units amounted to $19.6 million in 1999, $19.1 million in 1998 and $20 million in 1997. Nuclear decommissioning, as a cost of removal, is included in the accumulated provision for depreciation.

A Post-Shutdown Decommissioning Activities Report for Millstone 1 was filed with the Nuclear Regulatory Commission in June 1999 which outlines decommissioning activities, and costs, and supports the obligation recorded by the company. Nuclear decommissioning

expenses for Millstone 1 were $22.8 million in 1999, $17.3 million in 1998 and $17.7 million in 1997.

External decommissioning trusts have been established for the costs of decommissioning the Millstone units. Payments for CL&P's ownership share of the cost of decommissioning Seabrook is paid to an independent decommissioning financing fund managed by the state of New Hampshire. Funding of the estimated decommissioning costs assumes levelized collections for the Millstone units and escalated collections for Seabrook and after-tax earnings on the Millstone and Seabrook decommissioning funds of 5.5 percent and 6.5 percent, respectively.

As of December 31, 1999 and 1998, CL&P collected a total of $185.1 million and $165.6 million, respectively, through rates toward the future decommissioning costs of their shares of Millstone 2 and 3 and Seabrook, of which $164.2 million in 1999 and $145.8 million in 1998 have been transferred to external decommissioning trusts. Earnings on the decommissioning trusts increase the decommissioning trust balances and the accumulated reserves for depreciation. Unrealized gains and losses associated with the decommissioning trusts and financing funds also impact the balance of the trusts and the accumulated reserve for depreciation. The fair values of the amounts in the external decommissioning trusts were $282.2 million and $242.2 million at December 31, 1999 and 1998, respectively.

Yankee Companies: VYNPC owns and operates a nuclear generating unit with a service life that is expected to end in 2012. CL&P's ownership share of estimated costs, in year end 1999 dollars, of decommissioning this unit is $40.7 million. On October 15, 1999, VYNPC agreed to sell the unit for $22 million to an unaffiliated company. Among other commitments, the acquiring company agreed to assume the decommissioning cost of the unit after it is taken out of service, and the VYNPC owners have agreed to fund the uncollected decommissioning cost to a negotiated amount at the time of the closing of the sale.

As of December 31, 1999 and 1998, CL&P's remaining estimated obligation, including decommissioning for the units owned by CYAPC, YAEC and MYAPC, which have been shut down was $238.1 million and $277.8 million, respectively.

3. SHORT-TERM DEBT

Limits: The amount of short-term borrowings that may be incurred by CL&P is subject to periodic approval by either the SEC under the 1935 Act or by the respective state regulators. SEC authorization allowed CL&P, as of January 1, 1999, to incur total short-term borrowings up to a maximum of $375 million. In addition, the charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt the company may incur. As of December 31, 1999, CL&P's charter permits CL&P to incur $322 million of unsecured debt.

Credit Agreement: On November 19, 1999, CL&P and WMECO entered into a new 364-day revolving credit facility for $500 million, replacing the previous $313.75 million facility which was to expire on November 21, 1999. The revolving credit facility, will be used to bridge gaps in working capital and provide short-term liquidity. CL&P may draw up to $300 million under the facility, which is secured by second mortgages on Millstone 2 and 3. Unless extended, the new credit facility will expire on November 17, 2000. At December 31, 1999 and 1998, there were $90 million and $10 million, respectively, in borrowings under these facilities.

Under the credit agreement discussed above, CL&P may borrow at fixed or variable rates plus an applicable margin based upon the company's most senior secured debt as rated by the lower of Standard & Poor's or Moody's Investors Service. The weighted average interest rate on CL&P's notes payable to banks outstanding on December 31, 1999 and 1998, was 7.69 percent and 6.53 percent, respectively.

This credit agreement provides that CL&P must comply with certain financial and nonfinancial covenants as are customarily included in such agreements, including, but not limited to, common equity ratios and interest coverage ratios.

Money Pool: Certain subsidiaries of NU, including CL&P, are members of the Northeast Utilities System Money Pool (Pool). The Pool provides a more efficient use of the cash resources of the NU system and reduces outside short-term borrowings. NUSCO administers the Pool as agent for the member companies. Short-term borrowing needs of the member companies are first met with available funds of other member companies, including funds borrowed by NU parent. NU parent may lend to the Pool but may not borrow. Funds may be withdrawn from or repaid to the Pool at any time without prior notice. Investing and borrowing subsidiaries receive or pay interest based on the average daily federal funds rate. Borrowings based on loans from NU parent, however, bear interest at NU parent's cost and must be repaid based upon the terms of NU parent's original borrowing. At December 31, 1999 and 1998, CL&P had $11.7 million and no borrowings, respectively, from the Pool. The interest rate on borrowings from the Pool at December 31, 1999 and 1998, was 4.9 percent and 5.8 percent, respectively. Maturities of short-term debt obligations were for periods of three months or less.

4. LEASES

CL&P finances its respective shares of nuclear fuel for Millstone 2 and 3 under the Niantic Bay Fuel Trust (NBFT) capital lease agreement. This capital lease agreement has an expiration date of June 1, 2040. At December 31, 1999 and 1998, the present value of CL&P's capital lease obligation to the NBFT was $127.2 million and $144.8 million, respectively. In connection with the planned nuclear divestiture, CL&P anticipates that its portion of the NBFT capital lease will be terminated and CL&P's portion of the NBFT's obligation under the $180 million Series G Intermediate Term Note agreement will be assigned to CL&P.

CL&P makes quarterly lease payments for the cost of nuclear fuel consumed in the reactors based on a units-of-production method at rates which reflect estimated kilowatt-hours of energy provided plus financing costs associated with the fuel in the reactors. Upon permanent discharge from the reactors, CL&P's interest in the nuclear fuel transfers to CL&P.

CL&P also has entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, nuclear control room simulators, and office space. The provisions of these lease agreements generally provide for renewal options.

Capital lease rental payments charged to operating expense were $10 million in 1999, $20.5 million in 1998 and $10.5 million in 1997. Interest included in capital lease rental payments was $9.4 million in 1999, $14.1 million in 1998 and $9.9 million in 1997. Operating lease rental payments charged to expense were $14.3 million in 1999, $17.9 million in 1998 and $19.7 million in 1997.

Future minimum rental payments, excluding annual nuclear fuel lease payments and executory costs such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, as of December 31, 1999, are:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Year	Capital Leases	Operating Leases
	(Millions of Dollars)	
2000	$ 2.4	$16.1
2001	2.4	13.0
2002	2.4	11.3
2003	2.4	9.7
2004	2.3	8.6
After 2004	29.4	16.9
Future minimum lease payments	41.3	$75.6
Less amount representing interest	24.1	
Present value of future minimum lease payments for other than nuclear fuel	17.2	
Present value of future nuclear fuel lease payments	127.2	
Present value of future minimum lease payments	$144.4	

5. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Details of preferred stock not subject to mandatory redemption are:

Description	December 31, 1999 Redemption Price	Shares Outstanding December 31, 1999	December 31, 1999	December 31, 1998
			(Millions of Dollars)	
$1.90 Series of 1947	$52.50	163,912	$ 8.2	$ 8.2
$2.00 Series of 1947	54.00	336,088	16.8	16.8
$2.04 Series of 1949	52.00	100,000	5.0	5.0
$2.20 Series of 1949	52.50	200,000	10.0	10.0
3.90% Series of 1949	50.50	160,000	8.0	8.0
$2.06 Series E of 1954	51.00	200,000	10.0	10.0
$2.09 Series F of 1955	51.00	100,000	5.0	5.0
4.50% Series of 1956	50.75	104,000	5.2	5.2
4.96% Series of 1958	50.50	100,000	5.0	5.0
4.50% Series of 1963	50.50	160,000	8.0	8.0
5.28% Series of 1967	51.43	200,000	10.0	10.0
$3.24 Series G of 1968	51.84	300,000	15.0	15.0
6.56% Series of 1968	51.44	200,000	10.0	10.0
			$116.2	$116.2

6. PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

Details of preferred stock subject to mandatory redemption are:

Description	December 31, 1999 Redemption Price	Shares Outstanding December 31, 1999	December 31, 1999	December 31, 1998
			(Millions of Dollars)	
7.23% Series of 1992	$51.93	981,434	$ 49.1	$ 52.8
5.30% Series of 1993	50.67	1,009,340	50.5	66.5
			99.6	119.3
Less preferred stock to be redeemed within one year		395,000	19.8	19.8
			$ 79.8	$ 99.5

Each of these series is subject to certain refunding limitations for the first five years after issuance. Redemption prices reduce in future years.

The following table details redemption and sinking fund activity for preferred stock subject to mandatory redemption:

Series		Minimum Annual Sinking Fund Requirement	Shares Reacquired 1999	Shares Reacquired 1998
		(Millions of Dollars)		
7.23% Series of 1992	(1)	$ 3.8	75,000	443,566
5.30% Series of 1993	(2)	16.0	320,000	270,660

(1) Sinking fund requirements commenced September 1, 1998.
(2) Sinking fund requirements commenced October 1, 1999.

The minimum sinking fund requirements of the series subject each year to mandatory redemption aggregate $19.8 million each year for 2000 through 2002, $6.2 million in 2003, and $3.8 million in 2004. In case of default on sinking fund payments, no payments may be made on any junior stock by way of dividends or otherwise (other than in shares of junior stock) so long as the default continues. If CL&P is in arrears in the payment of dividends on any outstanding shares of preferred stock, CL&P would be prohibited from redeeming or purchasing less than all of the outstanding preferred stock.

7. LONG-TERM DEBT

Details of long-term debt outstanding are:

At December 31,	1999	1998
	(Millions of Dollars)	
First Mortgage Bonds:		
7 1/4% Series VV due 1999	$ -	$ 74.0
5 1/2% Series A due 1999	-	140.0
5 3/4% Series XX due 2000	159.0	200.0
7 7/8% Series A due 2001	160.0	160.0
7 3/4% Series C due 2002	200.0	200.0
6 1/8% Series B due 2004	-	140.0
7 3/8% Series TT due 2019	20.0	20.0
7 1/2% Series YY due 2023	-	100.0
8 1/2% Series C due 2024	115.0	115.0
7 7/8% Series D due 2024	140.0	140.0
7 3/8% Series ZZ due 2025	-	125.0
	794.0	1,414.0
Pollution Control Notes:		
Variable rate, due 2016-2022	46.4	46.4
Variable tax exempt, due 2028-2031	377.5	377.5
Fees and interest due for spent nuclear fuel disposal costs	183.4	175.0
Other	0.2	0.1
Less amounts due within one year	159.0	214.0
Unamortized premium and discount, net	(1.4)	(5.0)
Long-term debt, net	$1,241.1	$1,794.0

Long-term debt maturities and cash sinking fund requirements, excluding fees and interest due for spent nuclear fuel disposal costs, on debt outstanding at December 31, 1999, for the years 2000 through 2004 are $159 million, $160 million, $200 million, and minimal requirements for 2003 and 2004, respectively.

Essentially all utility plant of CL&P is subject to the liens of the company's first mortgage bond indenture.

CL&P has secured $315.5 million of pollution control notes with second mortgage liens on Millstone 1, junior to the liens of its first mortgage bond indenture.

CL&P has $62 million of tax-exempt Pollution Control Revenue Bonds with bond insurance secured by first mortgage bonds and a liquidity facility.

The average effective interest rate on the variable-rate pollution control notes ranged from 2.2 percent to 3.9 percent for 1999 and from 3.6 percent to 3.7 percent for 1998.

8. INCOME TAX EXPENSE

The components of the federal and state income tax provisions were charged/(credited) to operations as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Current income taxes:			
Federal......................	$197.7	$ (9.2)	$(53.3)
State........................	27.9	(3.9)	(3.3)
Total current.............	225.6	(13.1)	(56.6)
Deferred income taxes, net:			
Federal......................	(113.0)	(34.9)	8.4
State........................	(20.1)	(17.5)	(11.4)
Total deferred...........	(133.1)	(52.4)	(3.0)
Investment tax credits, net...	(7.3)	(13.3)	(7.4)
Total income tax expense/(credit)...........	$ 85.2	$ (78.8)	$(67.0)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The components of total income tax expense/(credit) are classified as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Income taxes charged to operating expenses..........	$122.1	$(11.7)	$(59.4)
Other income taxes............	(36.9)	(67.1)	(7.6)
Total income tax expense/(credit)...........	$ 85.2	$(78.8)	$(67.0)

Deferred income taxes are comprised of the tax effects of temporary differences as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Depreciation, leased nuclear fuel, settlement credits and disposal costs................	$ (9.9)	$ (5.6)	$ 12.0
Regulatory deferral.............	6.2	(36.7)	(12.4)
State net operating loss carryforward..................	7.8	1.1	(7.7)
Regulatory disallowance.........	(24.2)	(18.1)	-
Sale of fossil generation assets.............	(126.1)	-	-
Pension accruals................	9.8	8.9	6.5
Contractual settlements.........	0.6	1.3	1.8
Other...........................	2.7	(3.3)	(3.2)
Deferred income taxes, net......	$(133.1)	$(52.4)	$ (3.0)

A reconciliation between income tax expense/(credit) and the expected tax expense/(credit) at 35 percent of pretax income is as follows:

For the Years Ended December 31,	1999	1998	1997
	(Millions of Dollars)		
Expected federal income tax.....	$25.0	$(96.1)	$(72.3)
Tax effect of differences:			
Depreciation..................	36.5	20.9	19.5
Amortization of regulatory assets	22.5	22.7	3.9
Investment tax credit amortization................	(7.3)	(13.3)	(7.4)
State income taxes, net of federal benefit.............	5.1	(13.9)	(9.6)
Other, net....................	3.4	0.9	(1.1)
Total income tax expense/(credit)..............	$85.2	$(78.8)	$(67.0)

9. EMPLOYEE BENEFITS

A. Pension Benefits and Postretirement Benefits Other Than Pensions

The NU system companies, including CL&P, participate in a uniform noncontributory defined benefit retirement plan covering substantially all regular NU system employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. CL&P's portion of the NU system's total pension credit, part of which was credited to utility plant, was $40.3 million in 1999, $32.6 million in 1998 and $22.5 million in 1997.

Currently, CL&P annually funds an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code (the Code).

The NU system companies, including CL&P, also provide certain health care benefits, primarily medical and dental, and life insurance benefits through a benefit plan to retired employees. These benefits are available for employees retiring from CL&P who have met specified service requirements. For current employees and certain retirees, the total benefit is limited to two times the 1993 per retiree health care cost. These costs are charged to expense over the future estimated work life of the employee. CL&P annually funds postretirement costs through external trusts with amounts that have been rate-recovered and which also are tax deductible under the Code.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Pension and trust assets are invested primarily in domestic and international equity securities and bonds.

The following table represents information on the plans' benefit obligation, fair value of plan assets, and the respective plans' funded status:

At December 31,	Pension Benefits 1999	Pension Benefits 1998	Postretirement Benefits 1999	Postretirement Benefits 1998
(Millions of Dollars)				
Change in benefit obligation				
Benefit obligation at beginning of year	$ (562.7)	$(531.6)	$(133.8)	$(126.6)
Service cost	(11.0)	(9.8)	(2.3)	(2.0)
Interest cost	(40.0)	(37.5)	(9.3)	(9.2)
Plan amendment	(32.5)	-	-	-
Transfers	1.8	(6.3)	-	-
Actuarial gain/(loss)	58.8	(12.4)	(0.6)	(7.7)
Benefits paid	35.5	34.9	14.1	11.7
Settlements	(1.8)	-	-	-
Benefit obligation at end of year	$ (551.9)	$(562.7)	$(131.9)	$(133.8)
Change in plan assets				
Fair value of plan assets at beginning of year	$ 935.7	$ 846.4	$ 53.8	$ 46.1
Actual return on plan assets	135.8	117.9	6.6	6.1
Employer contribution	-	-	13.4	13.3
Benefits paid	(35.5)	(34.9)	(14.1)	(11.7)
Transfers	1.8	6.3	-	-
Fair value of plan assets at end of year	$1,037.8	$ 935.7	$ 59.7	$ 53.8
Funded status at December 31	$ 485.9	$ 373.0	$ (72.2)	$ (80.0)
Unrecognized transition (asset)/obligation	(4.6)	(5.5)	95.5	102.8
Unrecognized prior service cost	33.1	3.2	-	-
Unrecognized net gain	(400.9)	(295.8)	(23.3)	(22.8)
Prepaid benefit cost	$ 113.5	$ 74.9	$ -	$ -

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	1999	1998	1999	1998
Discount rate..................	7.75%	7.00%	7.75%	7.00%
Compensation/progression rate..	4.75	4.25	4.75	4.25
Health care cost trend rate (a)	N/A	N/A	5.57	5.22

(a) The annual per capita cost of covered health care benefits was assumed to decrease to 4.90 percent by 2001.

The components of net periodic benefit (credit)/cost are:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
(Millions of Dollars)	1999	1998	1997	1999	1998	1997
Service cost.....	$ 11.0	$ 9.8	$ 8.8	$ 2.3	$ 2.0	$ 1.7
Interest cost....	40.0	37.5	37.9	9.3	9.2	9.2
Expected return on plan assets.	(78.1)	(68.4)	(59.6)	(4.2)	(3.6)	(3.1)
Amortization of unrecognized net transition (asset)/ obligation......	(0.9)	(0.9)	(0.9)	7.3	7.4	7.3
Amortization of prior service cost...........	2.7	0.3	0.3	-	-	-
Amortization of actuarial gain..	(15.0)	(10.9)	(8.1)	-	-	-
Other amortization, net.............	-	-	-	(1.3)	(1.7)	(2.3)
Settlements......	-	-	(0.9)	-	-	-
Net periodic benefit (credit)/cost..	$ (40.3)	$(32.6)	$(22.5)	$13.4	$13.3	$12.8

For calculating pension and postretirement benefit costs, the following assumptions were used:

	For the Years Ended December 31,					
	Pension Benefits			Postretirement Benefits		
	1999	1998	1997	1999	1998	1997
Discount rate..........	7.00%	7.25%	7.75%	7.00%	7.25%	7.75%
Expected long-term rate of return.......	9.50	9.50	9.25	N/A	N/A	N/A
Compensation/ progression rate.....	4.25	4.25	4.75	4.25	4.25	4.75
Long-term rate of return - Health assets, net of tax.........	N/A	N/A	N/A	7.50	7.75	7.50
Life assets..........	N/A	N/A	N/A	9.50	9.50	9.25

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components......	$0.6	$(0.6)
Effect on postretirement benefit obligation...........	$7.3	$(7.2)

The trust holding the health plan assets is subject to federal income taxes.

B. **Employee Stock Ownership Plan**

In June 1999, CL&P paid NU parent $30.5 million for NU shares issued from 1992 through 1998 on behalf of its employees in accordance with NU's 401(k) plan. CL&P charged retained earnings for this payment, as compensation expense had already been recorded in the respective years at the fair market value of the shares allocated.

10. SALE OF CUSTOMER RECEIVABLES

As of December 31, 1999 and 1998, CL&P had sold accounts receivable of $170 million and $105 million, respectively, to a third-party purchaser with limited recourse through the CL&P Receivables Corporation (CRC), a wholly owned subsidiary of CL&P. In addition, at December 31, 1999 and 1998, $22.5 million and $11.6 million, respectively, of assets was designated as collateral under the agreement with CRC.

Concentrations of credit risk to the purchaser under the company's agreement with respect to the receivables are limited due to CL&P's diverse customer base within its service territory.

11. COMMITMENTS AND CONTINGENCIES

A. Restructuring

During 1999, restructuring orders were issued by the Connecticut Department of Public Utility Control (DPUC), which required CL&P to discontinue the application of SFAS No. 71 to the generation portion of its business and allowed for the recovery of the majority of its stranded costs. Stranded costs including regulatory assets will be collected through a transition charge through 2026. The restructuring orders also allowed for securitization of CL&P's nonnuclear regulatory assets and the costs to buyout or buydown the various purchased-power contracts. Securitization is the process of monetizing stranded costs through the sale of nonrecourse debt securities by a special purpose entity, collateralized by CL&P's interests in its stranded cost recoveries.

On December 15, 1999, the DPUC issued a supplemental decision approving the components of CL&P's rates for standard offer service commencing on January 1, 2000. The DPUC also approved an interim nuclear capital recovery mechanism for the period from January 1, 2000, until the nuclear units are sold at auction. In approving the rates, the DPUC denied recovery of most of the capital additions made to Millstone 2 and 3 subsequent to June 30, 1997, which CL&P has or will expend to maintain those plants in a safe and efficient condition or to maintain their auction value. If implemented as approved, CL&P would not recover a significant portion of the capital additions which have been or are expected to be incurred subsequent to July 1, 1997, until the plants are sold in 2001. On December 29, 1999, CL&P filed with the DPUC a petition for reconsideration of this portion of the order. The DPUC has agreed to reopen the docket to consider CL&P's petition. Management believes the restructuring legislation provides for the recovery of these prudently incurred expenditures. If CL&P is unsuccessful in favorably resolving this contingency, an impairment loss of $50 million would be recorded.

In September 1999, NU announced that the Millstone nuclear generation assets of CL&P will be put up for auction as soon as practical. On November 8, 1999, CL&P filed its divestiture plan for the Millstone units with the DPUC. The auction is expected to begin in early 2000, provided all regulatory approvals have been met, with a successful bidder chosen by mid 2000 and a closing in 2001. No NU system company will participate as a bidder in the auction process. Management expects to recover all of CL&P's nuclear stranded

costs through the net proceeds of generation asset sales and billing through a transition charge to retail customers.

B. Nuclear Litigation

The non-NU joint owners of Millstone 3 have filed demands for arbitration with CL&P and WMECO as well as lawsuits in Massachusetts Superior Court against NU and its current and former trustees related to the companies' operation of Millstone 3. During 1999, NU and these subsidiaries agreed in principle to settle with certain of the joint owners, who own 58 percent of the non-NU ownership of Millstone 3. The settlements provide for the payment to the claimants of $36.4 million and certain contingent payments.

Arbitration and litigation claims remain outstanding for the remaining joint owners who have not agreed to settle. Management cannot estimate the potential outcome of the arbitration and litigation for the nonsettled joint owners, therefore, no liability has been established at December 31, 1999.

C. Environmental Matters

The NU system, including CL&P, is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of our environment. As such, the NU system and CL&P have active environmental auditing and training programs and believe they are in compliance with the current laws and regulations.

However, the normal course of operations may necessarily involve activities and substances that expose CL&P to potential liabilities of which management cannot determine the outcome. Additionally, management cannot determine the outcome for liabilities that may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Management does not believe, however, that this will have a material impact on CL&P's financial statements.

Based upon currently available information for the estimated remediation costs at December 31, 1999 and 1998, the liability recorded by CL&P for its estimated environmental remediation costs amounted to $6.9 million and $8 million, respectively.

D. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982, CL&P must pay the DOE for the disposal of spent nuclear fuel and high-level radioactive waste. The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. Fees for nuclear fuel burned on or after April 7, 1983, are billed

currently to customers and paid to the DOE on a quarterly basis. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Fuel), an accrual has been recorded for the full liability and payment must be made prior to the first delivery of spent fuel to the DOE. Until such payment is made, the outstanding balance will continue to accrue interest at the 3-month treasury bill yield rate. As of December 31, 1999 and 1998, fees due to the DOE for the disposal of CL&P's Prior Period Fuel were $183.4 million and $175 million, respectively, including interest costs of $116.9 million and $108.5 million, respectively.

E. Nuclear Insurance Contingencies

Insurance policies covering CL&P's ownership share of the NU system's nuclear facilities have been purchased for the primary cost of repair, replacement or decontamination of utility property, certain extra costs incurred in obtaining replacement power during prolonged accidental outages and the excess cost of repair, replacement or decontamination or premature decommissioning of utility property.

CL&P is subject to retroactive assessments if losses under those policies exceed the accumulated funds available to the insurer. The maximum potential assessments with respect to losses arising during the current policy year for the primary property insurance program, the replacement power policies and the excess property damage policies are $7.1 million, $4.1 million and $8.9 million, respectively. In addition, insurance has been purchased by the NU system in the aggregate of $200 million on an industry basis for coverage of worker claims.

Under certain circumstances, in the event of a nuclear incident at one of the nuclear facilities covered by the federal government's third-party liability indemnification program, the NU system, including CL&P, could be assessed liabilities in proportion to its ownership interest in each of its nuclear units up to $83.9 million. The NU system's payment of this assessment would be limited to, in proportion to its ownership interest in each of its nuclear units, $10 million in any one year per nuclear unit. In addition, if the sum of all claims and costs from any one nuclear incident exceeds the maximum amount of financial protection, the NU system would be subject to an additional 5 percent or $4.2 million liability, in proportion to its ownership interests in each of its nuclear units. Based upon its ownership interests in the Millstone units and in Seabrook, CL&P's maximum liability, including any additional assessments, would be $192.9 million per incident, of which payments would be limited to $21.9 million per year. In addition, through purchased-power contracts with VYNPC, CL&P would be responsible for up to an additional assessment of $8.4 million per incident, of which payments would be limited to $1 million per year.

F. Construction Program

CL&P currently forecasts construction expenditures of $1.3 billion for the years 2000-2004, including $205.8 million for 2000. CL&P estimates that nuclear fuel requirements, including nuclear fuel financed through the NBFT, will be $137.5 million for the years 2000-2003, including $47.5 million for 2000.

G. Long-Term Contractual Arrangements

Yankee Companies: The NU system companies relied on VYNPC for 1.5 percent of their capacity under long-term contracts. Under the terms of its agreement, CL&P paid its ownership (or entitlement) shares of costs, which included depreciation, operation and maintenance (O&M) expenses, taxes, the estimated cost of decommissioning, and a return on invested capital. These costs were recorded as purchased-power expenses and recovered through CL&P's rates. CL&P's cost of purchases under contracts with VYNPC amounted to $17 million in 1999, $15.9 million in 1998 and $14.1 million in 1997. VYNPC has agreed to sell its nuclear unit. Upon completion of the sale, this long-term contract will be terminated.

Nonutility Generators (NUGs): CL&P has entered into various arrangements for the purchase of capacity and energy from NUGs. For the years ended December 31, 1999 and 1998, 13 percent and for the year ended December 31, 1997, 14 percent, of NU's system electricity requirements were met by NUGs. CL&P's total cost of purchases under these arrangements amounted to $293.8 million in 1999, $290.7 million in 1998 and $283.2 million in 1997. The company is in the process of renegotiating the terms of these contracts through either a contract buydown or buyout. The company expects any payments to the NUGs as a result of these renegotiations to be recovered from the company's customers.

Hydro-Quebec: Along with other New England utilities, CL&P has entered into an agreement to support transmission and terminal facilities to import electricity from the Hydro-Quebec system in Canada. CL&P is obligated to pay, over a 30-year period ending in 2020, its proportionate share of the annual O&M expenses and capital costs of those facilities.

Estimated Annual Costs: The estimated annual costs of CL&P's significant long-term contractual arrangements, absent the effects of any contract terminations or buydowns, are as follows:

	2000	2001	2002	2003	2004
	(Millions of Dollars)				
VYNPC........	$ 15.9	$ 16.5	$ 16.6	$ 16.2	$ 15.9
NUGs.........	291.0	292.5	296.2	301.7	283.3
Hydro-Quebec.	17.8	17.3	16.8	16.3	15.8

H. New England Power Pool (NEPOOL) Generation Pricing

Disputes with respect to interpretation and implementation of the NEPOOL market rules have arisen with respect to various competitive product markets. In certain cases, CL&P stands to gain as a result of resolution of such disputes. In other cases, CL&P could incur additional costs as the result of resolution of the disputes. The various disputes are in various stages of resolution through alternative dispute resolution and regulatory review. It is too early to tell the level of potential gain or loss that may result upon resolution of these issues.

12. MARKET RISK AND RISK MANAGEMENT INSTRUMENTS

Energy Price Risk Management: Beginning in 1997 through 1999, CL&P used swap instruments with financial institutions to hedge the energy price risk created by long-term negotiated energy contracts. These agreements were intended to minimize exposure associated with rising fuel prices by managing a portion of CL&P's cost of producing power for these negotiated energy contracts.

In 1999, CL&P divested substantially all of its fossil and hydroelectric generation assets and agreed to transfer the rights and obligations related to the long-term negotiated energy contracts to an unregulated affiliate. Accordingly, the fuel swap positions were marked-to-market and CL&P recognized a loss of $5.2 million. In January 2000, the fuel swap positions were liquidated.

13. MINORITY INTEREST IN CONSOLIDATED SUBSIDIARY

CL&P Capital LP (CL&P LP), a subsidiary of CL&P, previously had issued $100 million of cumulative 9.3 percent Monthly Income Preferred Securities (MIPS), Series A. CL&P has the sole ownership interest in CL&P LP, as a general partner, and is the guarantor of the MIPS securities. Subsequent to the MIPS issuance, CL&P LP loaned the proceeds of the MIPS issuance, along with CL&P's $3.1 million capital contribution, back to CL&P in the form of an unsecured debenture. CL&P consolidates CL&P LP for financial reporting purposes. Upon consolidation, the unsecured

debenture is eliminated, and the MIPS securities are accounted for as a minority interest.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Supplemental Executive Retirement Plan (SERP) Investments: CL&P's portion of the investments held for the benefit of the SERP are recorded at fair market value. These investments having a cost basis of $0.2 million held for benefit of the SERP were recorded at their fair market values at December 31, 1999 and 1998, of $1.3 million.

Nuclear decommissioning trusts: CL&P's portion of the investments held in the NU system companies' nuclear decommissioning trusts were marked-to-market by $88.2 million as of December 31, 1999, and $78.7 million as of December 31, 1998, with corresponding offsets to the accumulated provision for depreciation. The amounts adjusted in 1999 and 1998 represent cumulative net unrealized gains. The cumulative gross unrealized holding losses were immaterial for both 1999 and 1998.

Preferred stock and long-term debt: The fair value of CL&P's fixed-rate securities is based upon the quoted market price for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of CL&P's financial instruments and the estimated fair values are as follows:

	At December 31, 1999	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption...............	$ 116.2	$ 144.9
Preferred stock subject to mandatory redemption..................	99.6	96.8
Long-term debt - First mortgage bonds................	794.0	805.4
Other long-term debt................	607.3	564.5
MIPS	100.0	97.3

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	At December 31, 1998	
(Millions of Dollars)	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption..............	$ 116.2	$ 77.2
Preferred stock subject to mandatory redemption..................	119.3	108.1
Long-term debt - First mortgage bonds.................	1,414.0	1,421.9
Other long-term debt.................	598.9	601.2
MIPS	100.0	102.0

15. **OTHER COMPREHENSIVE INCOME**

The accumulated balance for each other comprehensive income item is as follows:

(Thousands of Dollars)	December 31, 1998	Current Period Change	December 31, 1999
Unrealized gains on securities.............	$ 638	$38	$676
Minimum pension liability adjustments...	(260)	-	(260)
Accumulated other comprehensive income....	$ 378	$38	$416

(Thousands of Dollars)	December 31, 1997	Current Period Change	December 31, 1998
Unrealized gains on securities.............	$ -	$ 638	$638
Minimum pension liability adjustments...	-	(260)	(260)
Accumulated other comprehensive income....	$ -	$ 378	$378

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The changes in the components of other comprehensive income are reported net of the following income tax effects:

	1999	1998	1997
(Thousands of Dollars)			
Unrealized gains on securities..............	$(26)	$(446)	$ -
Minimum pension liability adjustments...	-	182	-
Other comprehensive income..................	$(26)	$(264)	$ -

16. **SEGMENT INFORMATION**

Effective January 1, 1999, the NU system companies, including CL&P, adopted SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." The NU system is organized between regulated utilities and unregulated energy services. CL&P is included in the regulated utilities segment of the NU system and has no other reportable segments.

17. **MERGER AGREEMENT WITH CON EDISON**

On October 13, 1999, NU and Con Edison announced that they have agreed to a merger to combine the two companies. The shareholders of NU will receive $25 per share in a combination of cash and Con Edison common stock.

NU shareholders also have the right to receive an additional $1 per share if a definitive agreement to sell its interests (other than that now held by PSNH) in Millstone 2 and 3 is entered into and recommended by the Utility Operations and Management Unit of the DPUC on or prior to the later of December 31, 2000, or the closing of the merger. Further, the value of the amount of cash or common stock to be received by NU shareholders is subject to increase by an amount of $0.0034 per share per day for each day that the transaction does not close after August 5, 2000.

Upon completion of the merger, NU will become a wholly owned subsidiary of Con Edison. The purchase is subject to the approval of the shareholders of both companies and several regulatory agencies. The companies anticipate that these regulatory procedures can be completed by July 2000.

The Connecticut Light and Power Company and Subsidiaries

SELECTED CONSOLIDATED FINANCIAL DATA	1999	1998	1997	1996	1995
			(Thousands of Dollars)		
Operating Revenues..........	$2,452,855	$2,386,864	$2,465,587	$2,397,460	$2,387,069
Operating Income/(Loss).....	174,749	28,254	(7,619)	59,142	324,026
Net (Loss)/Income...........	(13,568)	(195,725)	(139,597)	(50,868)	205,216
Cash Dividends on Common Stock..............	-	-	5,989	138,608	164,154
Total Assets................	5,298,284	6,050,198	6,081,223	6,244,036	6,045,631
Long-Term Debt(a)...........	1,400,056	2,007,957	2,043,327	2,038,521	1,822,018
Preferred Stock Not Subject to Mandatory Redemption................	116,200	116,200	116,200	116,200	116,200
Preferred Stock Subject to Mandatory Redemption (a)............	99,539	119,289	155,000	155,000	155,000
Obligations Under Capital Leases (a)........	144,400	162,884	158,118	155,708	172,264

CONSOLIDATED QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
1999	March 31	June 30	September 30	December 31
		(Thousands of Dollars)		
Operating Revenues	$606,997	$565,069	$667,349	$613,440
Operating Income	$ 20,412	$ 24,370	$ 51,969	$ 77,998
Net(Loss)/Income	$(13,705)	$ (6,814)	$ 9,873	$ (2,922)
1998				
Operating Revenues	$ 608,961	$ 561,224	$ 628,148	$ 588,531
Operating Income/(Loss)	$ 6,261	$ 11,066	$ 29,945	$ (19,018)
Net Loss	$ (30,979)	$ (26,361)	$ (20,405)	$(117,980)

(a) Includes portion due within one year.

The Connecticut Light and Power Company and Subsidiaries

CONSOLIDATED STATISTICS (Unaudited)

	Gross Electric Utility Plant December 31, (Thousands of Dollars)	kWh Sales (Millions)	Average Annual Use Per Residential Customer (kWh)	Electric Customers (Average)	Employees December 31,
1999	$6,007,421	29,317	8,969	1,120,846	2,377
1998	6,345,215	27,356	8,476	1,111,370	2,379
1997	6,639,786	25,766	8,526	1,103,309	2,163
1996	6,512,659	26,043	8,639	1,099,340	2,194
1995	6,389,190	26,366	8,506(a)	1,094,527	2,285

(a) Effective January 1, 1996, the amounts shown reflect billed and unbilled sales. The 1995 amounts have been restated to reflect this change.

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The Connecticut Light and Power Company

First and Refunding Mortgage Bonds

Trustee and Interest Paying Agent
Bankers Trust Company, Corporate Trust
and Agency Group
P.O. Box 318, Church Street Station
New York, New York 10008-0318

Preferred Stock

Transfer Agent, Dividend Disbursing Agent and Registrar
Northeast Utilities Service Company Shareholder Services
P.O. Box 5006
Hartford, Connecticut 06102-5006

2000 Dividend Payment Dates
5.28%, 5.30%*, $3.24 Series
January 1, April 1, July 1, and October 1

4.50% (1956), 4.96%, 6.56%
$1.90, $2.00, $2.04, $2.06, $2.09, and $2.20 Series
February 1, May 1, August 1, and November 1

3.90%, 4.50% (1963), 7.23%* Series
March 1, June 1, September 1, and December 1

* These issues have been called for redemption on April 13.

Monthly Income Preferred Securities

9.30% Cumulative Monthly Income Preferred Securities (MIPS), Series A
2000 Payment Dates
January 31, February 29, March 31, May 1, May 31
June 30, July 31, August 31, October 2, October 31,
November 30, December 29.

Address General Correspondence in Care of:
Northeast Utilities Service Company
Investor Relations Department
P.O. Box 270

Data contained in this Annual Report are submitted for the sole purpose of providing information to present security holders about the Company.

General Offices
107 Selden Street
Berlin, Connecticut 06037-1616

BayCorp

HOLDINGS, LTD.

1999

ANNUAL REPORT

BayCorp
HOLDINGS, LTD.

Letter to Shareholders

1999 was a year of change, accomplishment and excitement for BayCorp. The Company looks very different today than it did a year ago. Major accomplishments in 1999 included (1) successful completion of the acquisition of an additional 34 megawatts of Seabrook capacity, bringing the total capacity owned to 174 megawatts, (2) solid operating performance at the Seabrook plant and realization of higher power prices in the Northeast wholesale power markets, and (3) successful development and launch of HoustonStreet.com, the first fully web-based trading floor and portal for electricity and other energy products. Our stock price reflected these accomplishments, reaching a high of $10.50 per share in December 1999 after languishing at a low of $1.88 in April 1999.

Seabrook Operations

Since most of the costs at Seabrook are fixed, the economics of the Seabrook plant are driven largely by two factors: (1) capacity factor, and (2) Northeast wholesale power prices. Capacity factor is the actual plant output divided by the output that would be achieved if the plant operated at its maximum capacity throughout the period. In 1999, Seabrook operated at a capacity factor of 85.6%. This includes a refueling outage of 48 days that occurred between March 27, 1999 and May 13, 1999. Since the end of the refueling outage in May, Seabrook has operated at a 98.9% capacity factor through March 31, 2000. This represents a very credible operating performance. In fact, Seabrook ranked 50th out of over 400 nuclear plants in the world for total generation output in 1999.

After an initial period of flat or declining prices in the first half of 1999, wholesale power prices rebounded significantly in the second half of the year. This was primarily the result of increased oil and gas prices. To a certain degree, because Seabrook utilizes nuclear fuel rather than fossil fuels to generate electricity, an investment in Seabrook represents a hedge against increasing fossil fuel prices. While new gas-fired generation is scheduled to be developed in New England over the next several years, the region is currently relatively dependent upon oil-fired generation for electricity production. Accordingly, power prices in New England are largely correlated to fluctuations in the price of oil. Overall, power prices earned by Great Bay increased 3% in 1999 as compared to 1998, to $31.30 per megawatt hour from $30.40 per megawatt hour. During the second half of 1999, power prices increased 13.1% over the first half of 1999, to $32.81 from $29.01. As you can see from the table on the following page, however, these prices were not sufficient to cover the cash operating costs of Seabrook over the last operating cycle. The average cash operating cost over the most recent operating cycle was $36.60 per megawatt hour. On a positive note, power prices in New England to date in 2000 have shown a marked increase over 1999. If Seabrook operates at a high capacity factor prior to the refueling outage scheduled to begin in October 2000, we expect to generate positive cash flow from operations in 2000.

HoustonStreet.com

The Internet is having a profound effect on the way companies do business. Forrester Research predicts that business-to-business e-commerce will grow to $2.7 billion in 2003. Moreover, Forrester predicts that energy-related transactions on the web will reach $266 billion by 2004 and many experts predict that energy related products may be the single largest traded commodity over the Internet. HoustonStreet.com is in the crosshairs of two major trends in the global economy, (1) growth of business-to-business e-commerce, and (2) deregulation of global energy markets.

HoustonStreet.com is an on-line trading floor and portal for energy products. We initially started with the launch of a trading floor for power in July 1999. We are scheduled to launch a trading floor for crude oil and refined products in May 2000 and a natural gas platform later in the summer. At the end of the day, achieving liquidity on HoustonStreet.com will be the key to its success. We believe one important way to achieve increased liquidity and trading volume is to partner with the trading companies that can actually use

HoustonStreet.com. This is why we have established key strategic relationships with Equiva Trading Company (the U.S. trading arm for Shell, Texaco and Saudi Aramco), Williams Energy Marketing and Trading and kRoad Ventures. These companies have invested directly in HoustonStreet and therefore have a vested interest in seeing HoustonStreet succeed. We are working hard to develop new relationships to solidify HoustonStreet's position as a leader in on-line energy trading. HoustonStreet's goal is to become the global leader in on-line energy trading.

We do not believe that HoustonStreet will achieve full and fair valuation in the public marketplace as a subsidiary of BayCorp. Accordingly, we are exploring various alternatives, including a potential initial public offering of HoustonStreet, to allow HoustonStreet to trade separately from BayCorp and achieve full valuation. In the end, however, it is important to stress that we are focused on building a long-term, sustainable business for HoustonStreet, not an IPO. The stock market may go through wild gyrations. It is not sustainable to develop a company that is dependent upon access to the public markets in order to remain in business.

Conclusion

In sum, these are exciting times for BayCorp. Our Seabrook asset is finally beginning to generate the financial returns we hoped it would achieve and HoustonStreet has great momentum in building its business. I assure you that we remain focused and dedicated to our primary objective – maximizing shareholder value.

Finally, several heartfelt acknowledgments. First, I want to thank the dedicated employees of BayCorp, HoustonStreet and Great Bay. The level of effort and commitment exhibited by our employees in 1999 was truly extraordinary. I understand the sacrifices that were made. Please know that your hard work, commitment and perseverance are deeply appreciated. Second, I want to thank our key "Web for the Web" partners for their efforts in launching HoustonStreet, including Sapient, MicroArts, Bowstreet, Genuity, and Beaupre. It is extremely rewarding to work with such talented and dedicated individuals that share our vision and commitment to the success of HoustonStreet. A number of these key partners have expressed their commitment and dedication to the future of HoustonStreet by investing directly in HoustonStreet. I look forward to sharing much success with our partners in the future. Lastly, I must inform you that our Chairman of the Board, John A. Tillinghast, will be stepping down and enjoying a well-deserved retirement after 50 years in the utility business. I want to express my sincere appreciation to John. As the first President and Chief Executive Officer of Great Bay Power Corporation and BayCorp Holdings, Ltd., John has demonstrated integrity, strong leadership and unwavering loyalty to the Company. John provided stability in the Company's early years while establishing a course that will serve the Company and its shareholders well for years to come. John has been a mentor to me on a personal and professional basis. It has been an honor to work with him. We wish John and his family all the very best in the years to come.

Frank W. Getman Jr.
President and CEO

April 2000

Cycle 6 Operating Costs

The Seabrook Nuclear Power Project operates on a nominal 18-month period between refueling outages. The actual period between refueling outages depends both on the amount of the fuel that is put into the reactor during refueling and the amount of unscheduled outages that occur during a given fuel cycle. At the end of each cycle, Seabrook begins a scheduled refueling outage to refuel the reactor and to perform maintenance. Because the Seabrook Project runs on a cycle that covers more than one fiscal year, financial comparisons on a year-to-year basis may not always provide the most useful information to the reader. Accordingly, the following selected financial information is intended to summarize the Company's cost structure over the most recent operating cycle, which lasted from July 1997 through May 1999. That was the sixth operating fuel cycle at Seabrook since the plant commenced operations in August 1990.

Selected BayCorp Financial Information

Seabrook Project Cycle 6 Refueling

Seabrook Cycle 6 Generation (kWh) (Great Bay Share)	1,876,275,660
	(unaudited, dollar amounts in thousands)
Cycle 6 Operating Cash Costs:	
Seabrook Operating and Maintenance	$ 34,464
Seabrook Administrative and General	7,158
Nuclear Fuel	6,306
New Hampshire Nuclear Station Taxes	1,744
Seabrook Station Local Property Taxes	3,924
Transmission	1,655
Capital Expenditures	4,793
Corporate Administrative and General	6,158
Decommissioning Trust Fund Payments	2,558
Total Cycle 6 Operating Costs	$ 68,760
Cycle 6 Operating Costs (cents per kWh)	$ 3.66

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 1999

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 1-12527

BAYCORP HOLDINGS, LTD.
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**02-0488443** *(I.R.S. Employer Identification No.)*
20 International Drive, Suite 301 **Portsmouth, New Hampshire** *(Address of principal executive offices)*	**03801-6809** *(Zip Code)*

Registrant's telephone number, including area code: (603) 431-6600

Securities registered pursuant to Section 12(b) of the Act:
Common Stock, $.01 par value
(Title of Class)

American Stock Exchange
(Name of each exchange on which registered)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes √ No ___

Indicate by check mark if disclosure of delinquent filers to Item 405 of Regulations S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [√]

As of March 27, 2000, the approximate aggregate market value of the voting stock held by non-affiliates of the registrant was $62,457,156 based on the last reported sale price of the registrant's Common Stock on the American Stock Exchange as of the close of business on March 27, 2000. There were 8,272,000 shares of Common Stock outstanding as of March 27, 2000.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Part of Form 10-K into which incorporated
Portions of the Registrant's Proxy Statement for the 2000 Annual Meeting of Shareholders	Items 10, 11, 12 & 13 of Part III

PART I

Item 1. *Business.*

Introduction

BayCorp Holdings, Ltd. ("BayCorp" or the "Company") is a holding company incorporated in Delaware in 1996. Through its subsidiaries, BayCorp operates in two business segments — an Internet-based energy trading and information business and a wholesale electricity generation and trading business.

The Company's majority-owned subsidiary, HoustonStreet Exchange, Inc. ("HoustonStreet"), developed and operates HoustonStreet.com, an Internet-based trading platform and information portal for wholesale energy traders. Currently, HoustonStreet offers an online trading exchange that allows utilities, independent power producers and power marketers to trade electricity over the Internet. HoustonStreet plans to develop and launch trading platforms for crude oil and refined products, natural gas and other energy-related commodities. HoustonStreet is also exploring opportunities to license its trading platform for use in other non-energy business-to-business markets.

The Company's two other subsidiaries, Great Bay Power Corporation ("Great Bay") and Little Bay Power Corporation ("Little Bay"), are electric generating and trading companies. BayCorp wholly owns Great Bay and Little Bay, which in turn own a combined 15% joint ownership interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire (the "Seabrook Project"). This ownership interest entitles the companies to approximately 174 megawatts of the Seabrook Project's power output. Great Bay and Little Bay are exempt wholesale generators ("EWGs") under the Public Utility Holding Company Act of 1935 ("PUHCA"). Unlike regulated public utilities, Great Bay and Little Bay have no franchise area or captive customers. The companies sell their power in the competitive wholesale power markets, including through HoustonStreet.com.

Great Bay was incorporated in New Hampshire in 1986 and was formerly known as EUA Power Corporation. Little Bay was incorporated in New Hampshire in 1998. Great Bay sells its power, including its share of the electricity output of the Seabrook Project in the wholesale electricity market, primarily in the Northeast United States. Little Bay sells its power solely to Great Bay under an intercompany agreement. Neither BayCorp nor its subsidiaries has operational responsibilities for the Seabrook Project. Great Bay currently sells all but approximately 10 MW of its share of the Seabrook Project capacity in the wholesale short-term market. In addition to selling its owned generation, Great Bay purchases power on the open market for resale to third parties.

Great Bay became a wholly-owned subsidiary of BayCorp in a corporate reorganization that involved a merger of a newly formed wholly-owned subsidiary of BayCorp with and into Great Bay on January 24, 1997. The consolidated assets and liabilities of Great Bay and its subsidiaries immediately before the reorganization were the same as the consolidated assets and liabilities of BayCorp and its subsidiaries immediately after the reorganization. This corporate structure enables BayCorp, either directly or through subsidiaries other than Great Bay and Little Bay, to engage in businesses that these subsidiaries would be prohibited from pursuing due to their status as EWG's under the PUHCA. BayCorp may in the future enter into new businesses or acquire existing businesses, both in energy related fields and possibly in unrelated fields.

Recent Developments

Wholesale Electricity Generation and Trading Business

In November 1999, Little Bay purchased its 2.9% joint ownership interest in the Seabrook Project from Montaup Electric Company, a subsidiary of Eastern Utilities Associates, for a purchase price of $3.2 million, plus approximately $1.7 million for certain prepaid items, primarily nuclear fuel and capital expenditures. In addition, Montaup prefunded the decommissioning liability associated with Little Bay's 2.9% joint ownership interest in the Seabrook Project by transferring approximately $12.4 million into Little Bay's decommissioning account, an irrevocable trust earmarked for Little Bay's share of Seabrook Project decommissioning expenses.

Internet-based Energy Trading and Information Business

In July 1999, HoustonStreet initially launched its Internet-based wholesale electricity trading exchange in the Northeast United States. In September 1999, HoustonStreet launched electricity trading throughout the United States. As of March 27, 2000, over 85% of the power trading companies in the United States and approximately 440 individual traders have registered on HoustonStreet. Nine of the top ten trading companies have registered on the site.

In February 2000, HoustonStreet sold $6.0 million of its common stock and Series A preferred stock to Equiva Trading Company ("Equiva"). Equiva is a hydrocarbon supply and trading partnership jointly-owned by Equilon Enterprises LLC ("Equilon") and Motiva Enterprises LLC ("Motiva"). Equilon is owned by Shell Oil Company and Texaco Inc. Motiva is owned by Shell Oil Company, Texaco Inc. and Saudi Refining Inc., an affiliate of Saudi Aramco.

Also in February 2000, HoustonStreet announced plans to launch one of the first Web exchanges for wholesale crude oil and refined products trading. At that time, HoustonStreet entered into agreements with Equiva under which Equiva will share its knowledge of the oil trading industry with HoustonStreet and will pay HoustonStreet at least $1.5 million over the next two years as minimum trading commissions generated through Equiva's use of HoustonStreet's crude and refined oil products trading exchange, once it is created and operated.

In addition to sales of its capital stock to Equiva, HoustonStreet sold $10.6 million of its capital stock in February and March 2000 to other investors including Williams Energy Marketing & Trading Company, Omega Advisors, Inc., Elliott Associates, L.P., Thomas H. Lee Company and Sapient Corporation. In total, HoustonStreet raised $16.6 million in gross proceeds through these stock sales. As a result, BayCorp owns approximately 53% of HoustonStreet's capital stock (on an as converted to common stock basis) as of March 27, 2000.

Wholesale Electricity Generation and Trading Business

BayCorp's principal wholesale electricity generation and trading assets are its 100% equity interests in Great Bay and Little Bay. The business of Great Bay and Little Bay consists of managing their joint ownership interests in the Seabrook Project and the sale in the wholesale power market of their share of electricity produced by the Seabrook Project. Neither Great Bay nor Little Bay has operational responsibility for the Seabrook Project. Great Bay is a party to one long-term power contract for approximately 10 MW of Great Bay's share of the Seabrook Project capacity. Great Bay has also entered into a one-year contract, as of November 19, 1999, with Little Bay to purchase all of the output from the portion of Seabrook owned by Little Bay. See "— Purchased Power Agreements." Great Bay's business strategy is to utilize unit contingent and firm forward sales contracts to maximize the value of its 174 MW power supply from the Seabrook Project.

Traditionally, Great Bay sold most of its share of the Seabrook Project electricity output under unit contingent contracts. Under unit contingent contracts, Great Bay is obligated to provide the buyer with power only when the Seabrook Project is operating. In late 1998, Great Bay began to sell some of its electricity as firm power, which entitles the buyer to electricity whether or not the Seabrook Project is operating. Buyers pay a premium for firm power over unit contingent power because they can rely on uninterrupted electricity. In order to supply firm power during Seabrook Project unscheduled outages, Great Bay purchases power from the spot market during these outages and resells that power to its firm power customers. Spot market sales are subject to price fluctuations based on the relative supply and demand of electricity. As a result of spot market power price fluctuations, Great Bay may have to purchase power at prices exceeding prices paid by Great Bay's firm power customers during outages. Although Great Bay bears the primary risk of these price fluctuations, Great Bay maintains insurance to protect Great Bay during periods of extreme price volatility, subject to certain deductibles and coverage limits. This insurance, provided by CIGNA and others, provides coverage through May 2002. In addition to selling its owned generation, Great Bay purchases power on the open market for resale to third parties in back-to-back transactions.

The Seabrook Project

The Seabrook Project is located on an 896-acre site in Seabrook, New Hampshire. It is owned by Great Bay, Little Bay and nine other utility companies, consisting of North Atlantic Energy Company, Connecticut Light and Power, The United Illuminating Company, Canal Electric Company, Massachusetts Municipal Wholesale Electric Company, New England Power Company, New Hampshire Electric Cooperative, Inc., Taunton Municipal Lighting Plant and Hudson Light & Power Department (together with Great Bay and Little Bay, the "Participants").

Seabrook Unit 1 is a 1,150-MW nuclear-fueled steam electricity generating station. It employs a four loop, pressurized water reactor and support auxiliary systems designed by the Westinghouse Electric Company. The reactor is housed in a steel-lined reinforced concrete containment structure and a concrete containment enclosure structure. Reactor cooling water is obtained from the Atlantic Ocean through a 17,000-foot-long intake tunnel and returned through a 16,500-foot-long discharge tunnel. The station has a remaining license life of 26 years. Seabrook Unit 1 delivers its generated power to the New England 345 kilovolt transmission grid, a major network of interconnecting lines covering New England, through three separate transmission lines emanating from the station. On March 15, 1990, the Participants received from the Nuclear Regulatory Commission ("NRC") a full power operating license that authorizes operation of Seabrook Unit 1 until October 2026. Commercial operation of Seabrook Unit 1 commenced on August 19, 1990. Management believes that Seabrook Unit 1 is in good condition.

Since the Seabrook Project was originally designed to consist of two generating units, Great Bay and Little Bay also own a combined 15% joint ownership interest in Seabrook Unit 2. Great Bay and Little Bay assigned no value to Seabrook Unit 2 because on November 6, 1986, the joint owners of the Seabrook Project voted to dispose of Unit 2. Thereafter, Great Bay wrote off its investment in Unit 2. Little Bay has no investment in Unit 2. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. However, there have been no material sales of Unit 2 assets since July 1996.

The Participants are considering additional plans regarding disposition of Seabrook Unit 2, but such plans have not yet been finalized and approved. Great Bay and Little Bay are unable to estimate the costs for which they will be responsible in connection with the disposition of Seabrook Unit 2. Because Seabrook Unit 2 was never completed or operated, costs associated with its disposition will not include any amounts for decommissioning. Great Bay and Little Bay currently pay their share of monthly expenses required to preserve and protect the value of the Seabrook Unit 2 components.

Joint Ownership of Seabrook

Great Bay, Little Bay and the other Participants are parties to the Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units (the "JOA"), which establishes the respective ownership interests of the Participants in the Seabrook Project and defines their responsibilities with respect to the ongoing operation, maintenance and decommissioning of the Seabrook Project. In general, all ongoing costs of the Seabrook Project are divided proportionately among the Participants in accordance with their ownership interests in the Seabrook Project. Ownership interests in the Seabrook Project are several and not joint, and each Participant is only liable for its share of the Seabrook Project's costs and not liable for any other Participant's share. Great Bay and Little Bay's combined joint ownership interest of 15% is the third largest interest among the Participants, exceeded only by the approximately 40% interest held by Northeast Utilities and its affiliates and the 17.5% interest held by The United Illuminating Company.

A Participant may sell any portion of its ownership interest to any entity that is engaged in the electric utility business in New England. Before such sale, however, such selling Participant must give certain other Participants the right of first refusal to purchase the interest on the same terms. Any Participant may transfer, free from the foregoing right of first refusal, any portion of its interest (a) to a wholly-owned subsidiary, (b) to another company in the same holding company system or a construction trust for the benefit of the transferor or another company in the same holding company system, or (c) in connection with a merger, consolidation or acquisition of substantially all of the properties or all of the generating facilities of a Participant.

The failure to make monthly payments under the JOA by owners of the Seabrook Project other than Great Bay and Little Bay may have a material effect on Great Bay and Little Bay if either should choose to pay a greater proportion of the Seabrook Unit 1 and Seabrook Unit 2 expenses in order to preserve the value of its share of the Seabrook Project. In the past, certain of the owners of the Seabrook Project other than Great Bay and Little Bay have not made their full respective payments. At the current time, the electric utility industry is undergoing significant changes as competition and deregulation are introduced into the marketplace. Some utilities, including certain Participants, have indicated in state regulatory proceedings that they may be forced to seek bankruptcy protection if regulators, as part of the industry restructuring, do not allow for full recovery of stranded costs. If a Participant other than Great Bay or Little Bay filed for bankruptcy, and that Participant was unable to pay its share of Seabrook Project expenses, Great Bay and/or Little Bay might choose to pay a greater portion of Seabrook Project expenses. In the past, the filing of bankruptcy by a Participant has not resulted in a failure to pay Seabrook Project expenses or an increase in the percentage of expenses paid by other Participants.

The JOA provides for a Managing Agent to carry out the daily operational and management responsibilities of the Seabrook Project. The current Managing Agent, appointed by certain of the Participants on June 29, 1992, is North Atlantic Energy Service Corporation ("NAESCO"), a wholly-owned subsidiary of Northeast Utilities. Northeast Utilities, in conjunction with certain of its affiliates, holds the largest joint ownership interest in the Seabrook Project, as described above. Certain material decisions regarding the Seabrook Project are made by an Executive Committee consisting of the chief executive officers of certain of the Participants or their designees. There are currently five members of the Executive Committee. The Executive Committee acts by a majority vote of its members, although any action of the Executive Committee may be modified by vote of 51% of the ownership interests. Frank W. Getman Jr., the Company's President and Chief Executive Officer, is currently a member of the Executive Committee and of the Audit Committee and is Chairperson of the Budget Subcommittee. Under the JOA, the managing agent of the Seabrook Project may be removed and a new managing agent appointed by a 51% interest of the Participants.

Marketing and Customers

Great Bay currently sells most of its power in the Northeast United States in the short-term wholesale power market. Great Bay is currently not dependent on any single customer because many utilities and marketers are willing to buy Great Bay's share of electricity from the Seabrook Project at substantially the same price. Prices in the short-term market are typically higher during the summer and winter because the demand for electrical power is higher during these periods in the Northeast United States. The Company utilizes unit contingent and firm forward sale contracts to maximize the value of the uncommitted portion of its 174 megawatt power supply from the Seabrook Project.

During 1999, sales by Great Bay to Connecticut Municipal Electric Energy Cooperative and Select Energy accounted for 29% and 24%, respectively, of total operating revenues. Sales by Little Bay to Great Bay represent 100% of its operating revenues. See Note 11 of Notes to the Financial Statements.

Purchased Power Agreements

Great Bay is party to a purchased power agreement, dated as of April 1, 1993 (the "UNITIL Purchased Power Agreement"), with UNITIL Power Corporation that provides for Great Bay to sell to UNITIL Power approximately 10 MW of power. The UNITIL Purchased Power Agreement commenced on May 1, 1993 and runs through October 31, 2010. The current price of power under the UNITIL Purchased Power Agreement is 5.38 cents per kilowatt-hour ("kWh"). The price is subject to increase in accordance with a formula that provides for adjustments at less than the actual rate of inflation. UNITIL Power has an option to extend the UNITIL Purchased Power Agreement for an additional 12 years until 2022.

The UNITIL Purchased Power Agreement is front-end loaded whereby UNITIL Power pays higher prices, on an inflation-adjusted basis, in the early years of the Agreement and lower prices in later years. The amount of the excess paid by UNITIL Power in the early years of the UNITIL Purchased Power Agreement is quantified in a "Balance Account" which increased annually to a total of $4.1 million in July 1998, and now

decreases annually, reaching zero in July 2001. If the UNITIL Purchased Power Agreement terminates prior to its scheduled termination, and if at that time there is a positive amount in the Balance Account, Great Bay is obligated to refund that amount to UNITIL Power.

To secure the obligations of Great Bay under the UNITIL Purchased Power Agreement, including the obligation to repay UNITIL Power the amount in the Balance Account, the UNITIL Purchased Power Agreement grants UNITIL Power a mortgage on Great Bay's interest in the Seabrook Project. This mortgage may be subordinated to first mortgage financing of up to a maximum amount of $80,000,000. The UNITIL Purchased Power Agreement further provides that UNITIL Power's mortgage will rank pari passu with other mortgages that may hereafter be granted by Great Bay to other purchasers of power from Great Bay to secure similar obligations, provided that (i) the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest may not exceed $80,000,000, and (ii) the combined total of all second mortgages on the Seabrook Interest may not exceed the sum of (a) $80,000,000 less the total amount of Great Bay's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

Great Bay entered into a power sales agreement, dated as of November 19, 1999, with Little Bay. Under the terms of the agreement, Little Bay sells, and Great Bay purchases, all of the output of the portion of Seabrook owned by Little Bay. This agreement is a unit power sale agreement. Accordingly, when all or part of Little Bay's interest in Seabrook is not producing, the obligation of Little Bay to sell (and of Great Bay to purchase) is proportionately eliminated. The initial term of this agreement is for one year. Great Bay and Little Bay expect to continue this agreement after the initial period. The agreement can be terminated at any time by mutual consent of the parties, after any notice required by law.

Competition

Great Bay sells its share of Seabrook electricity into the wholesale electricity market in the Northeast United States. There are a large number of suppliers to this market and a surplus of capacity, resulting in intense competition. A primary source of competition comes from traditional utilities, many of which presently have excess capacity. In addition, non-utility wholesale generators of electricity, such as independent power producers ("IPPs"), Qualifying Facilities ("QFs") and EWGs, as well as power marketers and brokers, actively sell electricity in this market.

Great Bay may face increased competition, primarily based on price, from all the foregoing sources in the future. Great Bay believes that it will be able to compete effectively in the wholesale electricity market because of the current low cost of electricity generated by the Seabrook Project in comparison with existing alternative sources.

NEPOOL

Great Bay is a member of the New England Power Pool ("NEPOOL") and is a party to the New England Power Pool Agreement (the "NEPOOL Agreement"). NEPOOL is a voluntary association of companies engaged in the electricity business in New England and its membership is open to all investor-owned, municipal and cooperative electric utilities in New England and other companies that transact business in the region's bulk power market. Certain end users of electricity may also become NEPOOL members. The NEPOOL Agreement imposes on its participants obligations concerning generating capacity reserves and the right to use major transmission lines.

On December 31, 1996, NEPOOL filed a restructuring plan with the Federal Energy Regulatory Commission ("FERC"), including proposed amendments to the NEPOOL Agreement and an open access transmission tariff. The filing was intended not only to comply with the FERC's open access for tight pools as set forth in FERC Order No. 888, but also to (1) transfer the region's transmission grid and generation operation to an independent system operator, (2) provide for a competitive generation market through a combination of bilateral trading and the formation of a regional power exchange and (3) qualify NEPOOL as a regional transmission group. Among other things, NEPOOL's restructuring is designed to function efficiently in a changing electric power industry and to permit regional transmission at rates that do not vary with distance. These changes are being implemented in stages that began in mid-1997.

The region's independent system operator, ISO New England, Inc. ("ISO-NE"), was established in July 1997 and is responsible for maintaining the safety and reliability of the transmission grid and bulk power market within the NEPOOL region. ISO-NE performs these functions under a services contract with NEPOOL. Since May 1, 1999 ISO-NE has administered a new bid-based wholesale market system in New England that is designed to provide a competitive and efficient generation market through an hourly clearing price mechanism.

Nuclear Power, Energy and Utility Regulation

The Seabrook Project and Great Bay and Little Bay, as part owners of a licensed nuclear facility, are subject to the broad jurisdiction of the NRC, which is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health and safety, environmental and antitrust matters. Great Bay and Little Bay have been, and will be, affected to the extent of their proportionate share by the cost of any such requirements made applicable to the Seabrook Project.

Great Bay and Little Bay are also subject to the jurisdiction of the FERC under Parts II and III of the Federal Power Act and, as a result, are required to file with FERC all contracts for the sale of electricity. FERC has the authority to suspend the rates at which Great Bay and Little Bay propose to sell power, to allow such rates to go into effect subject to refund and to modify a proposed or existing rate if FERC determines that such rate is not "just and reasonable." FERC's jurisdiction also includes, among other things, the sale, lease, merger, consolidation or other disposition of facilities, interconnection of certain facilities, accounts, service and property records.

Because they both are EWG's, Great Bay and Little Bay are not subject to the jurisdiction of the Securities and Exchange Commission ("SEC") under PUHCA. In order to maintain their EWG status, Great Bay and Little Bay must continue to engage exclusively in the business of owning and/or operating all or part of one or more "eligible facilities" and to sell electricity only at wholesale (i.e. not to end users) and activities incidental thereto. An "eligible facility" is a facility used for the generation of electric energy exclusively at wholesale or used for the generation of electric energy and leased to one or more public utility companies. The term "facility" may include a portion of a facility. In the case of Great Bay and Little Bay, their combined 15% joint ownership interest in the Seabrook Project comprises an "eligible facility."

The NHPUC and the regulatory authorities with jurisdiction over utilities in New Hampshire and state legislatures of several other states in which Great Bay sells electricity are considering or are implementing initiatives relating to the deregulation of the electric utility industry. Simultaneously with the deregulation initiatives occurring in each of the New England states, NEPOOL restructured to create and maintain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services. These markets commenced operation in May 1999. All of the deregulation initiatives open electricity markets to competition in the affected states. While Great Bay and Little Bay believe they are low-cost producers of electricity and will benefit from the deregulation of the electric industry, it is not possible to predict the impact of these various initiatives on the companies.

Nuclear Power Issues

Nuclear units in the United States have been subject to widespread criticism and opposition, which has led to construction delays, cost overruns, licensing delays and other difficulties. Various groups have sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste by litigation, legislation and participation in administrative proceedings. The Seabrook Project was the subject of significant public controversy during its construction and licensing and remains controversial. An increase in public concerns regarding the Seabrook Project or nuclear power in general could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

In the event of a permanent shutdown of any unit, NRC regulations require that the unit be completely decontaminated of any residual radioactivity. While the owners of the Seabrook Project are accumulating

monies in a trust fund to pay decommissioning costs, if these costs exceed the amount of the trust fund, the owners, including Great Bay and Little Bay, will be liable for the excess.

Nuclear Related Insurance

In accordance with the Price Anderson Act, the limit of liability for a nuclear-related accident is approximately $9 billion, effective November 18, 1994. The primary layer of insurance for this liability is $200 million of coverage provided by the commercial insurance market. The secondary coverage is approximately $9 billion, based on the approximately 106 currently licensed reactors in the United States. The secondary layer is based on a retrospective premium assessment of $83.9 million per nuclear accident per licensed reactor, payable at a rate not exceeding $10 million per year per reactor. In addition, the retrospective premium is subject to inflation based indexing at five-year intervals and, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection available, then each licensee can be assessed an additional 5% ($4.2 million) of the maximum retrospective assessment. With respect to the Seabrook Project, Great Bay and Little Bay would be obligated to pay their ownership share of any assessment resulting from a nuclear incident at any United States nuclear generating facility. Great Bay and Little Bay estimate their total maximum liability per nuclear accident currently would be an aggregate amount of approximately $12.6 million per accident, with a maximum annual assessment of about $1.5 million per incident, per year.

In addition to the insurance required by the Price Anderson Act, the NRC regulations require licensees, including the Seabrook Project, to carry all risk nuclear property damage insurance in the amount of at least $1.06 billion, which amount must be dedicated, in the event of an accident at the reactor, to the stabilization and decontamination of the reactor to prevent significant risk to the public health and safety.

Great Bay and Little Bay also independently purchase business interruption insurance from Nuclear Electric Insurance Limited ("NEIL"). The current policy is in effect from September 15, 1999 until April 1, 2000 and a renewal policy has been signed which will be in effect from April 1, 2000 until April 1, 2001. The policy provides for the payment of a fixed weekly loss amount of $670,000 in the event of an outage at the Seabrook Project of more than 23 weeks resulting from the property damage occurring from a "sudden fortuitous event, which happens by chance, is unexpected and unforeseeable." The maximum amount payable to Great Bay and Little Bay is a total of $90.6 million. Under the terms of the policy, Great Bay and Little Bay are subject to a potential retrospective premium adjustment of up to approximately $469,000 should NEIL's board of directors deem that additional funds are necessary to preserve the financial integrity of NEIL. Since NEIL was founded in 1980, there has been no retrospective premium adjustment; however, there can be no assurance that NEIL will not make retrospective adjustments in the future. The liability for this retrospective premium adjustment ceases six years after the end of the policy unless prior demand has been made.

Nuclear Fuel

The Seabrook Project's managing agent has made, or expects to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. Many of these arrangements are pursuant to multi-year contracts with concentrate and service providers. Based on the Seabrook Project's existing contractual arrangements, Great Bay and Little Bay believe that the Seabrook Project has available, or under supply contracts, sufficient nuclear fuel for operations through approximately 2003. Uranium concentrate and conversion, enrichment and fabrication services currently are available from a variety of sources. The cost of such concentrate and such services varies based upon market forces.

Nuclear Waste Disposal

Costs associated with nuclear plant operations include amounts for nuclear waste disposal, including spent fuel, as well as for the ultimate decommissioning of the plants. The Nuclear Waste Policy Act of 1982 (the "NWPA") requires the United States Department of Energy (the "DOE"), subject to various

contingencies, to design, license, construct and operate a permanent repository for high level radioactive waste and spent nuclear fuel, which are collectively referred to as "high level waste."

The joint owners of the Seabrook Project, through their managing agent NAESCO, entered into contracts with the DOE for high level waste disposal in accordance with the NWPA. Under these contracts and the NWPA, the DOE was required to take title to and dispose of the Seabrook Project's high level waste beginning no later than January 31, 1998. However, the DOE has announced that its first high level waste repository will not be in operation until 2010 at the earliest.

As a result of this delay, many states and nuclear plant operators, including NAESCO, sued the DOE for injunctive relief and monetary damages. Two U.S. Courts of Appeals ordered the DOE to proceed with its high level waste disposal obligations and ruled that plant operators are entitled to money damages from DOE. However, there can be no assurance that the Seabrook Project will collect damages from the DOE because, among other things, NAESCO's case against the DOE is still pending.

In February 1999, the DOE proposed to Congress an alternative interim plan for high level waste management. The DOE proposed to take legal title and responsibility for the waste (on-site at nuclear plants such as Seabrook) until a permanent repository becomes available. Ultimately, Congress rejected that proposal, and on March 22, 2000, Congress passed amendments to the NWPA that would require the DOE to begin accepting nuclear waste shipments at a Nevada site in 2007. However, President Clinton stated that he would veto this legislation and Congress is not expected to override Mr. Clinton's veto. Regardless of whether this legislation becomes law or alternative solutions are identified, nuclear plants such as Seabrook must retain high level waste on-site or make other storage provisions until the DOE begins receiving nuclear waste materials in accordance with the NWPA and its contracts.

The Seabrook Project increased its on-site storage capacity for low level waste ("LLW") in 1996 and that capacity is expected to be sufficient to meet the Project's storage requirements through 2006. In addition, the managing agent of the Seabrook Project has advised Great Bay that the Seabrook Project has adequate on-site storage capacity for high level waste until approximately 2010.

The Low-Level Radioactive Waste Policy Act of 1980 requires each state to provide disposal facilities for LLW generated within the state, either by constructing and operating facilities or by joining regional compacts with other states to jointly fulfill their responsibilities. However, the Low-Level Radioactive Waste Policy Amendments Act of 1985 permits each state in which a currently operating disposal facility is located (South Carolina, Nevada and Washington) to impose volume limits and a surcharge on shipments of LLW from states that are not members of their regional compact.

In April 1995, a privately owned facility in Utah was approved as a disposal facility for certain types of LLW. The Seabrook Project began shipping certain LLW to the Utah facility in December 1995. In 1999, the Seabrook Project also began shipping some LLW to a privately owned facility in Tennessee. All LLW generated by the Seabrook Project that exceeds the maximum radioactivity level of LLW accepted by these facilities is currently stored on-site at the Seabrook facility.

Decommissioning

NRC licensing requirements and restrictions are also applicable to the decommissioning of nuclear generating units at the end of their service lives, and the NRC has adopted comprehensive regulations concerning decommissioning planning, timing, funding and environmental review. Any changes in NRC requirements or technology can increase estimated decommissioning costs.

Great Bay and Little Bay are responsible for their pro rata share of the decommissioning and cancellation costs for Seabrook. Great Bay pays its share of decommissioning funding on a monthly basis. Little Bay's share of decommissioning costs was prefunded by Montaup Electric Company, the owner of the 2.9% interest in the Seabrook Project that Little Bay acquired in November 1999. As part of that acquisition, Montaup Electric Company transferred approximately $12.4 million into Little Bay's decommissioning account, an irrevocable trust earmarked for Little Bay's share of Seabrook Plant decommissioning expenses.

The Seabrook decommissioning funding schedule is determined by the New Hampshire Nuclear Decommissioning Financing Committee (the "NDFC"). The NDFC reviews the decommissioning funding schedule for the Seabrook Project at least annually and, for good cause, may increase or decrease the amount of the funds or alter the funding schedule.

In June 1999, the NDFC issued a Final Report and Order relating to proceeding NDFC 98-1, the comprehensive update of Seabrook Unit 1 Decommissioning Fund. For funding purposes, this Order reflects decommissioning beginning in 2015, shortening the funding period, which commenced in 1990, from 36 to 25 years. Great Bay began funding at an accelerated rate in 1998 in response to New Hampshire legislation, and as such, the accelerated funding required by this Order is not expected to have a material impact on Great Bay. Great Bay's 1999 decommissioning payments totaled approximately $1.7 million. Little Bay's decommissioning funding was not affected by the June 1999 NDFC Order.

Funds collected by Seabrook for decommissioning are deposited in an external irrevocable trust pending their ultimate use. The earnings on the external trusts also accumulate in the fund balance. The trust funds are restricted for use in paying the decommissioning of Unit 1. The investments in the trust are available for sale. Great Bay and Little Bay have therefore reported their investment in trust fund assets at market value and any unrealized gains and losses are reflected in equity. There was an unrealized holding loss of approximately $45,000 as of December 31, 1999.

Although the owners of the Seabrook Project are accumulating funds in an external trust to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners, including Great Bay and Little Bay, would remain liable for the excess.

In January 1997 and July 1997, the NRC staff ruled that Great Bay did not satisfy the NRC definition of "electric utility." In January 1998, Great Bay filed a petition with the NRC seeking NRC approval of Great Bay's proposal to fund decommissioning obligations. Great Bay's petition also sought, in the alternative, an NRC permanent exemption from the obligation of Great Bay to comply with the NRC regulations applicable to non "electric utility" owners of interests in nuclear power plants. In June 1998, the New Hampshire State legislature enacted legislation that provides that in the event of a default by Great Bay on its payments to the decommissioning fund, the other Seabrook joint owners would be obligated to pay their proportional share of such default. As a result of the enactment of this legislation, the NRC staff found that Great Bay complies with the decommissioning funding assurance requirements. In July 1998, the staff of the NRC notified Great Bay of the staff's determination that Great Bay complies with the decommissioning funding assurance requirements under NRC regulations.

In response to the New Hampshire legislation, Great Bay agreed to make accelerated payments to the Seabrook decommissioning fund such that Great Bay will have contributed sufficient funds by the year 2015 to allow sufficient monies to accumulate, with no further payments by Great Bay to the fund, to the full estimated amount of Great Bay's decommissioning obligation by the time the current Seabrook operating license expires in 2026. Based on the currently approved funding schedule and Great Bay's accelerated funding schedule, Great Bay's decommissioning payments will be approximately $1.8 million in 2000 and escalate at 4% each year thereafter through 2015.

The current estimated cost to decommission the Seabrook Project, based on a study performed in 1996 for the lead owner of the Seabrook Project, is approximately $565 million in 2000 dollars and $2.2 billion in 2026 dollars, assuming a remaining 26-year life for the facility and a future cost escalation rate of 5.0%. Based on this estimate, the present value of Great Bay and Little Bay's share of this liability as of December 31, 1999 was approximately $79 million.

On November 15, 1992, Great Bay's former parent, EUA, and certain other parties entered into a settlement agreement. Under the settlement agreement, EUA guaranteed an amount not to exceed $10 million of Great Bay's future decommissioning costs of Seabrook Unit 1 in the event that Great Bay is unable to pay its share of such decommissioning costs.

Environmental Regulation

The Seabrook Project, like other electric generating stations, is subject to standards administered by federal, state and local authorities with respect to the siting of facilities and associated environmental factors. The United States Environmental Protection Agency (the "EPA"), and certain state and local authorities, have jurisdiction over releases of pollutants, contaminants and hazardous substances into the environment and have broad authority in connection therewith, including the ability to require installation of pollution control devices and remedial actions. The NRC has promulgated a variety of standards to protect the public from radiological pollution caused by the normal operation of nuclear generating facilities.

The EPA issued a National Pollutant Discharge Elimination System ("NPDES") permit, valid for a period of five years, to NAESCO on October 30, 1993 authorizing discharges from Seabrook Station into the Atlantic Ocean and the Browns River in accordance with limitations, monitoring requirements and conditions specified in the permit. A renewal application was filed in April 1998 and supplemented in August, September of 1998 and in September 1999. NAESCO has advised Great Bay that the Seabrook Station's initial five-year NPDES permit will remain effective during the renewal process.

On August 31, 1994, the New Hampshire Department of Environmental Services issued to NAESCO permits to operate two auxiliary boilers and two emergency diesel generators in accordance with New Hampshire Revised Statutes Annotated Chapter 125-C. These permits, which were effective until August 31, 1997, prescribe limits for the emission of air pollutants into the ambient air as well as record keeping and other reporting criteria. NAESCO filed an application on July 16, 1996 for permits under Title V of the Clean Air Act. Upon the expiration of the State of New Hampshire permits, the conditions authorized by those permits remain in effect until the Title V permits are granted. NAESCO can not estimate when the Title V permits will be granted. Because the liabilities of the Participants under the JOA are several and not joint, in the event that NAESCO violates the emissions limits contained in its permits, if at all, Great Bay and Little Bay will be liable for their pro rata share of any costs and liabilities assessed for the emissions violations.

In some environmental areas, the NRC and the EPA have overlapping jurisdiction. Thus, NRC regulations are subject to all conditions imposed by the EPA and a variety of federal environmental statutes, including obtaining permits for the discharge of pollutants (including heat, which is discharged by the Seabrook Project) into the nation's navigable waters. In addition, the EPA has established standards, and is in the process of reviewing existing standards, for certain toxic air pollutants, including radionuclides, under the United States Clean Air Act which apply to NRC-licensed facilities. The effective date for the new EPA radionuclide standard has been stayed as applied to nuclear generating units. Environmental regulation of the Seabrook Project may result in material increases in capital and operating costs, delays or cancellation of construction of planned improvements, or modification or termination of operation of existing facilities. Management believes that Great Bay and Little Bay are in compliance in all material respects with applicable EPA, NRC and other regulations relating to pollution caused by nuclear generating facilities.

Internet-based Energy Trading and Information Business

BayCorp's subsidiary, HoustonStreet, developed and operates HoustonStreet.com, an Internet-based trading platform and information portal for wholesale energy traders. Currently, HoustonStreet offers an online trading exchange that allows utilities, independent power producers and power marketers to trade electricity over the Internet. HoustonStreet plans to develop and launch trading platforms for crude and refined oil products, natural gas and other energy-related commodities.

Industry Background

Today, almost all electricity and approximately half of all natural gas trading is conducted by telephone. As online exchanges develop and provide more accurate and comprehensive real-time information and faster execution of trades, HoustonStreet's management believes that energy traders will increasingly adopt the online trading method. In addition, management believes that trading companies facing increased competition and lower profit margins will utilize online trading technology to realize cost savings and efficiencies. Moreover, HoustonStreet's management believes that virtually all wholesale energy traders use the Internet

for certain aspects of their business, including scheduling power transmission and interfacing with various regulatory bodies and power pools, such as ISO New England, PJM ISO and CalPX. Since traders already use the Internet for other business activities, HoustonStreet's management believes that traders will also use the Internet for trading.

State of Wholesale Electricity Market

The electricity market in the United States can be divided into two categories based on the electricity producing entity. The first type of producer, the vertically integrated utility, generates power and sells it directly to its end users. The second type of producer, the independent power producer, generates electricity and sells it on a wholesale basis. Utilities and independent power producers trade wholesale electricity. Wholesale electricity can be traded multiple times, as traders routinely buy and sell power to accommodate varying delivery point and delivery time requirements.

In addition to utilities and independent power producers, electricity is traded by power marketers. Power marketers are independent middlemen that buy and sell wholesale electricity at market prices. Although power marketers traditionally do not own electrical generation, transmission or distribution assets, they are in some instances affiliated with enterprises that own such assets. Wholesale trading of electricity in the United States totaled approximately $70 billion in 1998, representing over 3 billion megawatt hours. According to *Power Markets Week*, power marketer sales alone reached 2.3 billion megawatt hours in 1998.

Electricity Trading and Deregulation

With the onset of electric utility deregulation in the United States, the wholesale power trading market has grown and changed significantly. Historically, electric utilities traded power among themselves primarily on a "real time" (electric power for the next hour) and "day ahead" (power for tomorrow) basis. Forward transactions (beyond the next day) were less common. With vertically integrated utilities, the need for wholesale trading is mainly driven by plant outages and maintenance. Traditional regulated utilities priced transactions based on cost and rate of return rather than market dynamics.

There are two primary factors driving the change and growth of the wholesale power trading market in the United States — the breakup of the vertically integrated model and the introduction of non-rate of return regulated participants. The break up of vertically integrated organizations has increased the need for the resulting organizations to engage in wholesale transactions. When utilities were vertically integrated, captive generation was used to serve captive load and transactions were used to fill in mismatches between the two. Unaffiliated load-serving and generation entities must purchase and sell power to conduct their ongoing businesses.

Three states, California, Pennsylvania and Massachusetts, have completed electric utility deregulation to date. These states represent approximately 13% of the United States' electricity consumption. In addition, 18 other states have enacted restructuring legislation to date. These states represent an additional approximately 35% of the United States' electricity consumption. HoustonStreet's management believes that the ongoing deregulation process will continue and thereby generate a substantially larger market for trading on HoustonStreet.com.

The HoustonStreet Solution

HoustonStreet.com is a comprehensive Internet-based trading platform and information portal for wholesale energy traders. Currently, HoustonStreet offers an easy to use, fully Internet-based trading exchange that allows utilities, independent power producers and power marketers to trade electricity over the Internet. HoustonStreet provides traders with the information and flexibility they need to post offers, make bids, counter and re-counter and close the transaction. HoustonStreet plans to develop and launch trading platforms for crude and refined oil products, natural gas and other energy-related commodities.

HoustonStreet offers flexibility and choice to traders and accommodates their needs by permitting transactions for any quantity, time period and delivery point. HoustonStreet also serves as an information

portal, providing traders with important information that could impact their trading strategy, such as weather forecasts, energy and general news headlines and links to regional power pool market clearing prices and plant outage information. Moreover, HoustonStreet can serve as the base from which users can begin their Internet activity, with additional links to stock prices, sports news and other sites of interest to traders.

Sources of Revenue

HoustonStreet receives a fee for every trade completed on its Web site. The transaction fees charged by HoustonStreet are at or below the commissions charged by telephone brokers. Commissions on energy trades typically range from 0.01% to 0.05% of the value of the energy traded online.

Services

PowerPit. Many power traders buy and sell electricity based on a need to deliver or receive power at a specific point, at a specific time and for a specific quantity. Accordingly, commonly traded standardized products used by other traders may not meet the needs of these traders. The standard products, also known as hub products, cover a limited set of delivery points for specific peak time periods in blocks of 50 megawatts. HoustonStreet's *PowerPit* trading platform allows traders to post bids and offers ranging from one megawatt for one hour to large blocks for multiple years at any delivery point.

SpeedWay. Other power traders trade hub products and do not need the flexibility of *PowerPit.* Their greatest needs are speed, ease of use and sophisticated trading functionality. HoustonStreet's *SpeedWay* platform supports trading of standard hub products only. By limiting the product range, *SpeedWay* reduces the time and effort required to post bids and offers. *SpeedWay* allows traders to trade in both location spreads (simultaneously buying and selling power for the same time period for two different geographic points) and calendar spreads (buying and selling for the same point at two different time periods.)

Features and Benefits

HoustonStreet serves as a portal to other sites providing content valuable for individuals involved in the power market. The information available on HoustonStreet, such as weather forecasts, energy news and regional power pool market clearing prices, helps make the site "sticky" by providing traders with the information they need to obtain price discovery, analyze opportunities and execute trades. In addition, HoustonStreet provides other information of interest to traders, including real-time stocks and sports information.

Equiva Relationship

In February 2000, HoustonStreet sold $6.0 million of its common stock and Series A preferred stock to Equiva Trading Company ("Equiva"). Equiva is a hydrocarbon supply and trading partnership jointly-owned by Equilon Enterprises LLC ("Equilon") and Motiva Enterprises LLC ("Motiva"). Equilon is owned by Shell Oil Company and Texaco Inc. Motiva is owned by Shell Oil Company, Texaco Inc. and Saudi Refining Inc., an affiliate of Saudi Aramco.

Also in February 2000, HoustonStreet entered into agreements with Equiva under which Equiva will share its knowledge of the oil trading industry with HoustonStreet and will pay HoustonStreet at least $1.5 million over the next two years as minimum trading commissions generated through Equiva's use of HoustonStreet's crude and refined oil products trading exchange, once it is created and operated.

Pursuant to additional agreements, Equiva committed to make markets and promote liquidity for all of the primary products traded on HoustonStreet's crude and refined oil products trading exchange. HoustonStreet's management believes that Equiva's reputation as a leader in the energy trading markets, coupled with Equiva's commitment to make markets on HoustonStreet, increases the probability of success for HoustonStreet's crude and refined oil products exchange.

Notwithstanding HoustonStreet's relationship with Equiva or any other strategic partner or financial investor, HoustonStreet provides a neutral, secure and anonymous trading platform. HoustonStreet does not take title to any products traded on HoustonStreet.com nor compete with any users of the system.

Competition

HoustonStreet's electricity trading exchange competes with brokers who arrange for electricity trades by telephone and to a lesser extent, electronic brokerage services. Moving traders from the telephone to the Internet is perhaps the largest competitive challenge facing HoustonStreet. Currently, most transactions are conducted on the telephone either directly between two traders or through a telephone broker. The broker does not act as a principal in the transaction. The purchasing and selling entities are disclosed to each other upon completion of every transaction. This process can be inefficient and time consuming. In addition, the human element in the telephone broker market introduces a risk of error or omission in the dissemination of market information. The level of price transparency is low.

Independent Electronic Brokerages. HoustonStreet is aware of several electronic brokerages currently in operation that to a varying extent compete with HoustonStreet. Bloomberg PowerMatch is operated by Bloomberg Financial Services, a major provider of financial market information and analytical services through a proprietary system. Bloomberg's proprietary system is required to use its PowerMatch service. Altra Energy Technologies, Inc. has recently released a partially Web enabled trading platform, Altrade. This platform uses the Internet to communicate but requires proprietary software that must reside on the users' desktop. Open Access Technologies Incorporated (OATI) offers an Internet-based system for real time traders in the Mid-Continent Area Power Pool (MAPP) region of the country. HoustonStreet's management believes that none of these providers has a fully Web enabled comprehensive platform comparable to HoustonStreet.

Single Participant Web Sites. In addition, HoustonStreet is aware of several energy companies that have announced Internet-based systems that are designed to give users the ability to trade energy-related commodities with only that company. These Web sites are not independent exchanges, but rather Internet-based distribution systems for company-specific products and services. HoustonStreet is uncertain whether competitors of these energy companies will want to transact business on a single-company site, possibly providing competitors with information about positions they are taking in the market.

Customers

As of March 27, 2000, traders from approximately 20 companies have traded electricity on HoustonStreet.com. Approximately 440 individual traders and over 85% of power trading companies in the United States have registered to use HoustonStreet, including nine of the top ten power trading companies as ranked by *Power Markets Week* based on sales.

Marketing

HoustonStreet's management believes that there are approximately 1,000 electricity traders in the United States who potentially could trade power on HoustonStreet.com. This limited number of traders provides HoustonStreet with the opportunity to do a highly focused direct marketing campaign. This includes direct mail, direct e-mail and personal face-to-face visits from HoustonStreet's sales force.

As HoustonStreet implements its plans to expand into additional energy markets, it will need to expand its marketing campaign. In addition to direct marketing efforts, HoustonStreet intends to utilize its relationship with Equiva to promote HoustonStreet's planned crude and refined oil products trading exchange. HoustonStreet expects to enter into similar strategic relationships to facilitate planned expansion into natural gas and other markets.

Employees and Management

As of March 17, 2000, BayCorp and its subsidiaries had 35 employees, including 26 at HoustonStreet, seven at BayCorp and two employees at Great Bay. Little Bay has no employees.

BayCorp has entered into Management and Administrative Services Agreements (the "Services Agreements"), with its subsidiaries, Great Bay and HoustonStreet, pursuant to which BayCorp provides Great Bay and HoustonStreet a full range of management services, including general management and administration, accounting and bookkeeping, budgeting and regulatory compliance. Under the Services Agreements, Great Bay paid BayCorp $2,021,760 and HoustonStreet paid BayCorp $427,600 for such services in 1999. Each Services Agreement has a one-year term and provides for automatic one-year renewals. Although BayCorp and Little Bay do not currently have a services agreement in place, the companies expect to enter into a services agreement in 2000.

Item 2. ***Properties.***

BayCorp's principal assets include its 100% equity interests in Great Bay and Little Bay and approximately 53% equity interest in HoustonStreet as of March 27, 2000. In turn, Great Bay and Little Bay's principal asset is a combined 15% joint ownership interest in the Seabrook Project. The Seabrook Project is a nuclear-fueled, steam electricity, generating plant located in Seabrook, New Hampshire, which was planned to have two Westinghouse pressurized water reactors, Seabrook Unit 1 and Seabrook Unit 2 (each with a rated capacity of 1,150 megawatts), utilizing ocean water for condenser coiling purposes. Seabrook Unit 1 entered commercial service on August 19, 1990. Seabrook Unit 2 has been canceled. See "Business — The Seabrook Project."

BayCorp's corporate headquarters is located in Portsmouth, New Hampshire where it occupies approximately 3,960 square feet of office space under a lease that expires in July 2003. BayCorp's management believes that the corporate headquarters in Portsmouth, New Hampshire meets its current requirements and that additional space can be obtained to meet requirements for the foreseeable future.

HoustonStreet's corporate headquarters is also located in Portsmouth, New Hampshire where it occupies approximately 2,300 square feet of office space under a lease that expires in November 2000. HoustonStreet also occupies approximately 2,100 square feet of office space in Houston, Texas. HoustonStreet's management believes that the corporate headquarters in Portsmouth, New Hampshire and its office space in Houston, Texas meet its current requirements and that additional space can be obtained to meet requirements for the foreseeable future.

Item 3. ***Legal Proceedings.***

For each of the tax years 1994, 1995, 1996, 1997 and 1998, Great Bay filed property tax abatement applications with the towns of Hampton and Hampton Falls. The abatement requests were denied. Great Bay filed appeals for each of those years with the New Hampshire Board of Tax and Land Appeals (the "BTLA"). On November 11, 1999, Great Bay reached agreements settling the property tax litigation. As a result of the settlement agreement, Great Bay received $146,450 from the Town of Hampton and $21,967 from the Town of Hampton Falls. With regard to Hampton Falls, the settlement established an assessed valuation of $7,000,000 for 1999 and $2,500,000 for 2000. With regard to the Town of Hampton, the settlement established an assessed valuation of $20,000,000 for 1999 and $15,000,000 for 2000.

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

Not Applicable.

Executive Officers of the Registrant

The executive officers of BayCorp are:

Name	Age	Position
Frank W. Getman Jr.	36	Chief Executive Officer, President and Secretary
John A. Tillinghast	72	Chief Engineer, Chairman of the Board of Directors

Frank W. Getman Jr. has served as Chief Executive Officer, President, and Secretary of the Company since May 1998. Mr. Getman served as Chief Operating Officer of the Company since September 1996 and Vice President, Secretary and General Counsel of Great Bay since August 1995. From September 1991 to August 1995, Mr. Getman was an attorney with the law firm of Hale and Dorr LLP, Boston, Massachusetts. Mr. Getman holds J.D. and M.B.A. degrees from Boston College and a B.A. in Political Science from Tufts University.

John A. Tillinghast has served as the Company's Chief Engineer since May 1998 and the Chairman of the Board of Directors of the Company and its predecessor since November 1994. From April 1995 until May 1998, Mr. Tillinghast was the Company's Chief Executive Officer. Since 1987, Mr. Tillinghast has served as President and the sole stockholder of Tillinghast Technology Interests, Inc., a private consulting firm. From 1986 to 1993, Mr. Tillinghast served as Chairman of the Energy Engineering Board of the National Academy of Sciences. He holds an M.S. in Mechanical Engineering from Columbia University.

PART II

Item 5. *Market for Registrant's Common Equity and Related Stockholder Matters.*

Following are the reported high and low sales prices of BayCorp Common Stock ("MWH") on the American Stock Exchange ("ASE") as reported in the Wall Street Journal daily as traded, for each quarter during 1999 and 1998 that BayCorp Common Stock traded on the ASE:

	High	Low
1998		
First Quarter	6 9/16	6 3/8
Second Quarter	7 1/4	7
Third Quarter	6 11/16	5 1/4
Fourth Quarter	4 3/4	3 1/2

	High	Low
1999		
First Quarter	4 7/16	3 1/2
Second Quarter	6	3 3/8
Third Quarter	7 5/16	6
Fourth Quarter	9 11/16	6 1/4

As of March 17, 2000, the Company had 27 holders of record of its Common Stock. The Company believes that as of March 17, 2000, the Company had approximately 884 beneficial holders of its Common Stock. The number of beneficial owners substantially exceeds the number of record holders because many of the Company's stockholders hold their shares in street name.

BayCorp has never paid cash dividends on its common stock and currently expects that it will retain all of its future earnings and does not anticipate paying a dividend in the foreseeable future.

Item 6. *Selected Financial Data.*

Selected Financial Data

The following table sets forth selected financial data and other operating information of BayCorp, as successor to Great Bay.

The following data presents selected financial data of the Company as of and for the years ended December 31, 1999, December 31, 1998, December 31, 1997, December 31, 1996 and December 31, 1995. The information below should be read in conjunction with the "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Company's financial statements, including the notes thereto, contained elsewhere in this Report.

SELECTED FINANCIAL DATA
(Dollars in Thousands)

	For the Years Ended December 31,				
	1999	1998	1997	1996	1995
Income Statement Data:					
Operating Revenues	$ 45,761	$ 32,034	$ 26,642	$ 30,324	$ 24,524
Operating Expenses	48,520	37,310	36,880	32,563	32,381
Net Income (Loss)	(4,740)	(6,769)	(11,215)	4,100	(6,059)
Balance Sheet Data:					
Cash, Cash Equivalents & Short Term Investments	6,064	12,055	19,092	28,775	16,469
Working Capital	11,678	17,761	23,079	30,552	20,516
Total Assets	159,184	140,358	140,158	152,418	138,771
Decommissioning Liability	79,443	60,274	55,846	53,215	50,899
Capitalization:					
Common Equity	66,246	71,359	78,139	89,625	82,233
Total Capitalization	66,246	71,359	78,139	89,625	82,233

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Overview

Currently, BayCorp derives substantially all of its revenue through its energy trading activities and its 100% equity interest in Great Bay and Little Bay. Great Bay and Little Bay are electric generating companies whose principal asset is a combined 15% joint ownership interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire. The Company anticipates that it will derive additional revenues from Houston Street. HoustonStreet began charging commissions in September 1999 on wholesale power trades made on HoustonStreet.com.

BayCorp reported net losses for the years ended December 31, 1999, 1998 and 1997. The 1999 net loss was primarily due to costs associated with the refueling outage that began on March 27, 1999, with the Plant resuming full operating capacity on May 21, 1999, and to expenses associated with the start up of HoustonStreet. The 1998 net loss was primarily due to unscheduled outages at the Seabrook Project that occurred during the year and to the charge related to the termination of a power marketing agreement between Great Bay and PECO. The 1997 net loss was primarily due to scheduled and unscheduled outages at the Seabrook Project that occurred during that year.

The Seabrook Project from time to time experiences both scheduled and unscheduled outages. BayCorp incurs losses during outage periods due to the loss of all revenues from the sale of generation and additional costs associated with the outages as well as continuing operating and maintenance expenses and depreciation.

Unscheduled outages or operation of the unit at reduced capacity can occur due to the automatic operation of safety systems following the detection of a malfunction. In addition, it is possible for the unit to be shut down or operated at reduced capacity based on the results of scheduled and unscheduled inspections and routine surveillance by Seabrook Project personnel. It is not possible for BayCorp to predict the frequency or duration of any future unscheduled outages, however, it is likely that such unscheduled outages will occur. The Seabrook Project conducted a refueling outage in 1999. Refueling outages are generally scheduled every 18 months depending upon the Seabrook Project capacity factor and the rate at which the nuclear fuel is consumed.

The following discussion focuses solely on operating revenues and operating expenses that are presented in a substantially consistent manner for all of the periods presented.

Results of Operations

Operating Revenues

BayCorp's operating revenues for 1999 increased by approximately $13.7 million, or 42.9%, to $45,761,000 as compared with $32,034,000 for 1998. This increase was primarily due to an increase in sales by Great Bay of power purchased in the open market in 1999. The 1999 capacity factor at the Seabrook Project was 85.6% of the rated capacity as compared to a capacity factor of 83.3% for 1998. Operating revenues and the capacity factor were adversely impacted in 1999 by the scheduled refueling outage at the Seabrook Project that began on March 27. The Plant resumed full operating capacity on May 21 and operated at full capacity through December 31, 1999. In contrast, while there was no refueling outage in 1998, the Seabrook Project had approximately 64 unscheduled outage days in 1998. Substantially all of the Company's operating revenues in 1999 were generated by its wholesale electricity generation and trading business. HoustonStreet revenues in 1999 were nominal.

Sales of electricity increased by approximately 38.2% to 1,457,110,270 kilowatt-hours ("kWhs") in 1999 as compared to 1,054,203,800 kWhs in 1998. During 1999, the sales price per kWh (determined by dividing total sales revenue by the total number of kWhs sold in the applicable period) increased 3% to 3.13 cents per kWh as compared with 3.04 cents per kWh in 1998. Great Bay's cost of power (determined by dividing total operating expenses by kilowatt-hours sold during the applicable period) decreased 5.9% to 3.33 cents per kWh in 1999 as compared to 3.54 cents per kWh in 1998. This decrease was primarily the result of the higher capacity factor at the Seabrook Project during 1999 as compared to 1998. Scheduled and unscheduled outage time increases Great Bay's cost of power because Seabrook Project costs are spread over fewer kWhs.

BayCorp's operating revenues for 1998 increased by approximately $5.4 million, or 20.1%, to $32,034,000 as compared with $26,642,000 for 1997. This increase was primarily due to less scheduled and unscheduled outage time at the Seabrook Project during 1998. During 1998, the capacity factor at the Seabrook Project was 83.3% of the rated capacity as compared to a capacity factor of 78.3% for 1997. Operating revenues and capacity factor were adversely impacted in 1997 by the scheduled refueling outage at the Seabrook Project that began on May 10, 1997, lasting 50 days, and by the unscheduled outage that began on December 5, 1997, lasting 41 days. In contrast, there was no refueling outage in 1998; however, the Seabrook Project had approximately 64 unscheduled outage days in 1998.

Sales of electricity increased by approximately 9.4% to 1,054,203,800 kilowatt-hours in 1998 as compared to 964,038,400 kilowatt-hours in 1997. Operating revenues were favorably affected in 1998 by an increase in the sales price per kWh. During 1998, the sales price per kWh (determined by dividing total sales revenue by the total number of kWhs sold in the applicable period) increased 10.1% to 3.04 cents per kWh as compared with 2.76 cents per kWh in 1997. Great Bay's cost of power (determined by dividing total operating expenses by kilowatt-hours sold during the applicable period) decreased 7.6% to 3.54 cents per kWh in 1998 as compared to 3.83 cents per kWh in 1997. This decrease was primarily the result of the higher capacity factor at the Seabrook Project during 1998 as compared to 1997.

Expenses

BayCorp's total operating expenses for 1999 increased $11.2 million, or 30%, in comparison with 1998. This increase was primarily the result of purchased power expenses in 1999. Purchased power expenses increased approximately $11,186,000, from $1,046,000 in 1998 to $12,232,000 in 1999. Purchased power expenses have increased primarily because Great Bay purchased power in 1999 in the open market to resell to third parties and to cover firm sales during outages at the Seabrook Project in 1999. As Great Bay enters into more sales transaction agreements to supply firm power, Great Bay's expenses to purchase power to cover firm power obligations during scheduled and unscheduled outages may increase. Production costs decreased approximately $2.6 million, or 12.5%, from $20.8 million in 1998 to $18.2 million in 1999. This decrease was primarily the result of fewer unscheduled outage days in 1999 compared to 1998. Administrative and general expenses increased approximately $1.3 million, or 16.3%, from $8 million in 1998 to $9.3 million in 1999. Depreciation and amortization increased approximately $454,000, or 12.4%, from $3.7 million in 1998 to $4.1 million in 1999. The increase in administration and general expenses and depreciation expense was primarily due to expenses relating to the startup, commercial launch and expansion of HoustonStreet.

In 1999, the Company recognized $806,000 in unrealized losses on firm energy trading contracts. There was no comparable charge in 1998. In December 1998, the Emerging Issues Task Force reached consensus on Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities ("EITF 98-10"). EITF 98-10 is effective for fiscal years beginning after December 15, 1998. EITF 98-10 requires energy trading contracts to be recorded at fair value on the balance sheet, with the changes in fair value included in earnings. The effects of initial application of EITF 98-10 have been reported as a cumulative effect of a change in accounting principle. Financial statements for periods prior to initial adoption of EITF 98-10 have not been restated. The cumulative effect of this accounting change as of January 1, 1999 was an increase in net income of approximately $159,000 to recognize gains on net open physical purchase and sales commitments considered to be trading activity.

Other Deductions increased $646,000, or 43.3%, in 1999 as compared to 1998. This increase was primarily attributable to interest income, which decreased $387,000, or 41.3%, in 1999 as compared to 1998. This decrease was attributable to the lower cash balances in 1999 as compared to 1998. Decommissioning cost accretion increased $447,000, or 15.6%, to $3.3 million in 1999 as compared to $2.9 million in 1998. This accretion is a non-cash charge that reflects Great Bay's liability related to the closure and decommissioning of the Seabrook Project in current year dollars over the licensing period during which the Seabrook Project is licensed to operate. Decommissioning trust fund income increased $142,000, or 23.2%, to $755,000 in 1999 as compared to $613,000 in 1998. The increase in interest earned on the decommissioning trust fund reflected the higher 1999 fund balance as Great Bay continues to make contributions to the decommissioning trust fund.

BayCorp's total operating expenses (excluding depreciation and taxes) for 1998 increased $1.4 million, or 5.1%, in comparison with 1997. This increase was primarily the result of the costs associated with the unscheduled outages in 1998, including Great Bay's purchased power expenses of approximately $1.0 million that covered firm sales of approximately $1.2 million during unscheduled outages in 1998.

Operating expenses were also adversely impacted by payments to PECO of approximately $3.1 million in 1998, which included the charge related to the termination of the power marketing agreement with PECO for approximately $2.5 million in June 1998. Charges for PECO's marketing service in 1997 were approximately $1.8 million. In addition, depreciation and amortization increased $148,000, or 4.2%. Taxes other than income decreased $1.2 million, or 29.2%, in 1998 as compared to 1997 due to the Seabrook Project property tax settlement that resulted in a property tax refund to Great Bay in December 1998 of approximately $1.3 million.

Other Deductions increased $516,000, or 52.8%, in 1998 as compared to 1997. This increase was primarily attributable to interest income, which decreased $314,000, or 25.1%, in 1998 as compared to 1997. This decrease was attributable to the lower cash balances in 1998 as compared to 1997. Decommissioning cost accretion increased $210,000, or 7.9%, to $2.9 million in 1998 as compared to $2.7 million in 1997. Decommissioning trust fund income increased $143,000, or 30.4%, to $613,000 in 1998 as compared to $470,000 in 1997.

Net Operating Losses

For federal income tax purposes, as of December 31, 1999, the Company had net operating loss carry forwards ("NOLs") of approximately $225 million, which are scheduled to expire between 2005 and 2019. Because the Company has experienced one or more ownership changes, within the meaning of Section 382 of the Internal Revenue Code of 1986, as amended, an annual limitation is imposed on the ability of the Company to use $136 million of these carryforwards. The Company's best estimate at this time is that the annual limitation on the use of $136 million of the Company's NOLs is approximately $5.5 million per year. Any unused portion of the $5.5 million annual limitation applicable to the Company's restricted NOL's is available for use in future years until such NOL's are scheduled to expire. The Company's other $89 million of NOLs are not currently subject to such limitations.

Liquidity and Capital Resources

In 1999, cash generated from electricity sales by Great Bay and Little Bay was sufficient to cover the ongoing cash requirements of Great Bay, Little Bay and BayCorp. If the Seabrook Project operates at a capacity factor below historical levels, or if expenses associated with the ownership or operation of the Seabrook Project, including without limitation decommissioning costs, are materially higher than anticipated, or if the prices at which Great Bay is able to sell its share of the Seabrook Project electricity do not increase at the rates and within the time expected by Great Bay, BayCorp or Great Bay would be required to raise additional capital, either through a debt financing or an equity financing, to meet their ongoing cash requirements. There can be no assurance that BayCorp or Great Bay will be able to raise additional capital on acceptable terms or at all.

The Company's principal asset available to serve as collateral for borrowings is Great Bay's and Little Bay's combined 15% interest in the Seabrook Project. Pursuant to a purchased power agreement, dated as of April 1, 1993, between Great Bay and UNITIL Power Corp., Great Bay's interest in the Seabrook Project is encumbered by a mortgage. This mortgage may be subordinated by up to $80 million of senior secured financing. See "Business — Wholesale Electricity Generation and Trading Business — Purchased Power Agreements."

HoustonStreet began charging commissions for its services in September 1999. Commission revenues earned by HoustonStreet have been significantly less than HoustonStreet's ongoing cash requirements, including cash needed for development and expansion. HoustonStreet expects to continue to incur cash deficits. HoustonStreet expects to cover its cash deficits with the proceeds from sales of its capital stock. As of March 27, 2000, HoustonStreet raised $16.6 million in cash from sales of its capital stock and had cash on hand of $5.0 million. HoustonStreet will need to raise additional capital in the second quarter of 2000 or shortly thereafter to meet its ongoing cash needs. There can be no assurance that HoustonStreet will be able to raise additional capital on acceptable terms or at all.

Excluding cash held by HoustonStreet, the Company had cash and cash equivalents, restricted cash and short-term investments of approximately $6.1 million at December 31, 1999. In addition, BayCorp held a promissory note payable by HoustonStreet at December 31, 1999 for approximately $4.1 million. This note was repaid to BayCorp in February 2000.

BayCorp's total cash and short-term investments decreased approximately $6.0 million during 1999. The principal factors affecting liquidity during 1999 were cash used in connection with Little Bay's acquisition of its 2.9% joint ownership interest in the Seabrook Project and cash used in connection with forming, developing and expanding HoustonStreet. Non-cash charges to income included $4.1 million for depreciation, $4.0 million for nuclear fuel amortization, unrealized loss on firm energy trading contracts of $647,000 and $3.3 million for decommissioning trust fund accretion. There was an increase in accounts payable and other miscellaneous current liabilities of approximately $2.1 million primarily due to HoustonStreet payables for Web site development costs. Offsetting these non-cash charges to income were cash charges including a $1.6 million increase in December 1999 accounts receivable and other current assets as compared to December 1998. 1999 year end receivables reflected an increase in the amount of power sold, primarily due to the sale of Little Bay's power. Other cash charges included charges of $4.9 million for capital expenditures and $2.0 million for nuclear fuel.

Also in 1999, Little Bay purchased a 2.9% interest in the Seabrook Project from Montaup Electric Company, a subsidiary of Eastern Utilities Associates, for a purchase price of $3.2 million, plus approximately $1.7 million for certain prepaid items, primarily nuclear fuel and capital expenditures.

Great Bay's 1999 decommissioning payments totaled approximately $1.7 million. The decommissioning funding schedule is determined by the NDFC, which reviews the schedule for the Seabrook Project at least annually. Great Bay expects to use revenues from the sale of power to make these decommissioning payments. See "Business — Wholesale Electricity Generation and Trading Business — Decommissioning."

The Company anticipates that capital expenditures for HoustonStreet for the fiscal year 2000 will total approximately $20.0, million primarily for software development. Great Bay and Little Bay anticipates that their share of the Seabrook Project's capital expenditures for the 2000 fiscal year will total approximately $8.4 million for nuclear fuel and various capital projects. In addition, Great Bay and Little Bay are required under the JOA to pay their share of Seabrook Unit 1 and Seabrook Unit 2 expenses, including, without limitation, operation and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of the level of Seabrook Unit 1's operations.

Certain Factors That May Affect Future Results

This Annual Report on Form 10-K contains forward-looking statements. For this purpose, any statements contained herein that are not statements of historical fact may be deemed to be forward-looking statements. Without limiting the foregoing, the words "believes," "anticipates," "plans," "expects," "intends" and similar expressions are intended to identify forward-looking statements. There are a number of important factors that could cause the results of BayCorp and/or its subsidiaries to differ materially from those indicated by such forward-looking statements. These factors include, without limitation, those set forth below and elsewhere in this Annual Report.

History of Losses

BayCorp has never reported an operating profit for any year since its incorporation. Historically, electricity sales at short-term rates have not resulted in sufficient revenue to enable BayCorp to meet its cash requirements for operations, maintenance and capital related costs. In addition, HoustonStreet has incurred substantial operating expenses and capital expenditures, totaling approximately $6.2 million from formation to December 31, 1999, with continuing losses in 2000. These expenses and capital expenditures greatly exceeded HoustonStreet's revenue of $59,200 for the same period. HoustonStreet expects to continue to incur substantial operating losses for the foreseeable future. Moreover, there can be no assurance that Great Bay or Little Bay will be able to sell power at prices that will enable them to meet their cash requirements.

Liquidity Needs

As of December 31, 1999, BayCorp had approximately $6.1 million in cash and cash equivalents, restricted cash and short-term investments. The Company believes that such cash, together with the anticipated proceeds from the sale of electricity by Great Bay and Little Bay and additional external financing that HoustonStreet is currently seeking, will be sufficient to enable the Company and its subsidiaries to meet their cash requirements in 2000. However, if in 2000 or thereafter, the Seabrook Project operated at a capacity factor below historical levels, or if expenses associated with the ownership or operation of the Seabrook Project, including without limitation decommissioning costs, are materially higher than anticipated, or if the prices at which Great Bay and Little Bay are able to sell their share of the Seabrook Project electricity do not increase at the rates and within the time expected by Great Bay and Little Bay, or if HoustonStreet expenses materially exceed budgeted expenses, the Company or its subsidiaries would be required to raise additional capital, either through a debt financing or an equity financing, to meet ongoing cash requirements. In any event, in 2000 or shortly thereafter, the Company and its subsidiaries will likely need to raise additional capital from outside sources. There is no assurance that the Company or its subsidiaries would be able to raise such capital or that the terms on which any additional capital is available would be acceptable. If additional funds are raised by issuing equity securities, dilution to then existing stockholders will result.

Factors Related to Great Bay and Little Bay

Primary Reliance on a Single Asset. BayCorp's principal source of revenue is its wholesale electricity generation and trading business, which depends in large part on Great Bay and Little Bay's 15% combined joint interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire. Accordingly, BayCorp's results of operations significantly depend on the successful and continued operation of the Seabrook Project. In particular, if the Seabrook Project experiences unscheduled outages of significant duration, BayCorp's results of operations will be materially adversely affected.

Changes in the New England Wholesale Power Market. During recent years in New England, the combination of (1) increased competition in the wholesale power market, (2) small increases in the demand for electricity and (3) electric industry deregulation has resulted in increased uncertainty regarding the price of electricity in the wholesale power market. Although Great Bay's average selling price per kWh (determined by dividing total sales revenue by the total number of kWhs sold in the applicable period) increased from 2.76 cents in 1997 to 3.04 cents in 1998 and 3.13 cents in 1999, there can be no assurance that Great Bay or Little Bay will be able to sell their power at these prices or higher prices in the future.

Risks in Connection with Joint Ownership of Seabrook Project. Great Bay and Little Bay are required under the JOA to pay their share of Seabrook Unit 1 and Seabrook Unit 2 expenses, including without limitation operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by Great Bay or Little Bay to make their monthly payments under the JOA entitles certain other joint owners of the Seabrook Project to purchase Great Bay or Little Bay's interest in the Seabrook Project for 75% of the then fair market value thereof.

In addition, the failure to make monthly payments under the JOA by owners of the Seabrook Project other than Great Bay and Little Bay may have a material adverse effect on the Company. For example, Great Bay or Little Bay could opt to pay a greater proportion of the Seabrook Project expenses in order to preserve the value of their share of the Seabrook Project. In the past, certain of the owners of the Seabrook Project other than Great Bay and Little Bay have not made their full respective payments. The electric utility industry is undergoing significant changes as competition and deregulation are introduced into the marketplace. Some utilities, including certain Participants, have indicated in state regulatory proceedings that they may be forced to seek bankruptcy protection if regulators, as part of the industry restructuring, do not allow for full recovery of stranded costs. If a Participant other than Great Bay or Little Bay filed for bankruptcy and that Participant was unable to pay its share of Seabrook Project expenses, Great Bay or Little Bay might opt to pay a greater portion of Seabrook Project expenses in order to preserve the value of their share of the Seabrook Project. In the past, the filing of bankruptcy by a Participant has not resulted in a failure to pay Seabrook Project expenses or an increase in the percentage of expenses paid by other Participants.

The Seabrook Project is owned by Great Bay, Little Bay and the other owners thereof as tenants in common, with the various owners holding varying ownership shares. This means that Great Bay and Little Bay, which together own only a 15% interest, do not have control of the management of the Seabrook Project. As a result, decisions may be made affecting the Seabrook Project notwithstanding Great Bay and/or Little Bay's opposition.

Certain costs and expenses of operating the Seabrook Project or owning an interest therein, such as certain insurance and decommissioning costs, are subject to increase or retroactive adjustment based on factors beyond the control of BayCorp or its subsidiaries. The cost of disposing of Unit 2 of the Seabrook Project is not known at this time. These various costs and expenses may adversely affect BayCorp, Great Bay and Little Bay, possibly materially.

Extensive Government Regulation. The Seabrook Project is subject to extensive regulation by federal and state agencies. In particular, the Seabrook Project, and Great Bay and Little Bay as part owners of a licensed nuclear facility, are subject to the broad jurisdiction of the NRC, which is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health and safety, environmental and antitrust matters. Great Bay and Little Bay are also subject to the jurisdiction of the FERC

and, as a result, are required to file with FERC all contracts for the sale of electricity. FERC's jurisdiction also includes, among other things, the sale, lease, merger, consolidation or other disposition of facilities, interconnection of certain facilities, accounts, service and property records. Noncompliance with NRC requirements may result, among other things, in a shutdown of the Seabrook Project.

The NRC has promulgated a broad range of regulations affecting all aspects of the design, construction and operation of a nuclear facility, such as the Seabrook Project, including performance of nuclear safety systems, fire protection, emergency response planning and notification systems, insurance and quality assurance. The NRC retains authority to modify, suspend or withdraw operating licenses, such as the license pursuant to which the Seabrook project operates, at any time that conditions warrant. For example, the NRC might order Seabrook Unit 1 shut down (i) if flaws were discovered in the construction or operation of Seabrook Unit 1, (ii) if problems developed with respect to other nuclear generating plants of a design and construction similar to Unit 1, or (iii) if accidents at other nuclear facilities suggested that nuclear generating plants generally were less safe than previously believed.

Risk of Nuclear Accident. Nuclear reactors have been used to generate electric power for more than 35 years and there are currently more than 100 nuclear reactors used for electric power generation in the United States. Although the safety record of these nuclear reactors in the United States generally has been very good, accidents and other unforeseen problems have occurred both in the United States and elsewhere, including the well-publicized incidents at Three Mile Island in Pennsylvania and Chernobyl in the former Soviet Union. The consequences of such an accident can be severe, including loss of life and property damage, and the available insurance coverage may not be sufficient to pay all the damages incurred.

Public Controversy Concerning Nuclear Power Plants. Substantial controversy has existed for some time concerning nuclear generating plants and over the years such opposition has led to construction delays, cost overruns, licensing delays, demonstrations and other difficulties. The Seabrook Project was the subject of significant public controversy during its construction and licensing and remains controversial. An increase in public concerns regarding the Seabrook Project or nuclear power in general could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

Waste Disposal; Decommissioning Cost. There has been considerable public concern and regulatory attention focused upon the disposal of low- and high-level nuclear wastes produced at nuclear facilities and the ultimate decommissioning of such facilities. As to waste disposal concerns, both the federal government and the State of New Hampshire are currently delinquent in the performance of their statutory obligations.

The joint owners of the Seabrook Project, through their managing agent NAESCO, entered into contracts with the DOE for high level waste disposal in accordance with the NWPA. Under these contracts and the NWPA, the DOE was required to take title to and dispose of the Seabrook Project's high level waste beginning no later than January 31, 1998. However, the DOE has announced that its first high level waste repository will not be in operation until 2010 at the earliest.

The Seabrook Project increased its on-site storage capacity for low level waste ("LLW") in 1996 and that capacity is expected to be sufficient to meet the Project's storage requirements through 2006. In addition, the managing agent of the Seabrook Project has advised the Joint Owners that the Seabrook Project has adequate on-site storage capacity for high level waste until approximately 2010. If the Seabrook Project were unable to store nuclear waste on site or make other disposal provisions, the Company's business, results of operations and financial condition would be materially and adversely affected. See "Business — Wholesale Electricity Generation and Trading Business — Nuclear Waste Disposal."

As to decommissioning, NRC regulations require that upon permanent shutdown of a nuclear facility, appropriate arrangements for full decontamination and decommissioning of the facility be made. These regulations require that during the operation of a facility, the owners of the facility must set aside sufficient funds to defray decommissioning costs. While the owners of the Seabrook Project are accumulating monies in a trust fund to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners (including Great Bay and Little Bay) would remain liable for the excess. Moreover, the

amount that is required to be deposited in the trust fund is subject to periodic review and adjustment by an independent commission of the State of New Hampshire, which could result in material increases in such amounts.

Intense Competition. Great Bay sells its share (and Little Bay's share) of Seabrook Project electricity primarily into the Northeast United States wholesale electricity market. There are a large number of suppliers to this market and competition is intense. A primary source of competition comes from traditional utilities, many of which presently have excess capacity. In addition, non-utility wholesale generators of electricity, such as IPPs, QFs and EWGs, as well as power marketers and brokers, actively sell electricity in this market. Great Bay may face increased competition, primarily based on price, from all sources in the future.

Factors Related to HoustonStreet

Limited Operating History. HoustonStreet was incorporated in Delaware on April 27, 1999. HoustonStreet.com was launched initially in the Northeast on July 8, 1999 and nationwide on September 13, 1999. HoustonStreet has only a limited operating history upon which to evaluate its performance.

Significant Future Losses Expected. HoustonStreet's business is subject to the risks and uncertainties encountered by companies in early stages of development, particularly enterprises in new and rapidly evolving markets, such as electronic trading of energy products over the Internet. HoustonStreet's substantial operating expenses and capital expenditures from formation to date have greatly exceeded its revenues over the same period. HoustonStreet expects to continue to incur substantial operating losses for the foreseeable future. Moreover, there is no assurance that HoustonStreet will be able to achieve or sustain profitability.

Internet-based Wholesale Energy Trading is a New and Evolving Market. Wholesale trading of energy products over the Internet is a new and rapidly evolving market. HoustonStreet cannot be certain that a viable market will emerge or be sustainable. If the market for Internet-based wholesale energy trading fails to develop, if it develops more slowly than expected, if it becomes saturated with competitors or if it does not achieve widespread market acceptance, HoustonStreet would be materially adversely affected.

Dependence on Internet-based Wholesale Energy Trading. Substantially all of HoustonStreet's revenues depend on the continued and expanded use of Internet-based wholesale energy trading platforms. HoustonStreet currently depends on its wholesale electricity trading platform for all revenues. HoustonStreet will likely depend on other energy trading platforms, including platforms for oil and natural gas trading, if planned expansion is successful.

Businesses have only recently begun significant use of the Internet for electronic commerce. Although Internet usage has grown dramatically, HoustonStreet cannot assure you that usage will continue to increase for commerce or trading wholesale energy products. A decrease in the use of the Internet or a reduction in the currently anticipated growth in the use of the Internet would have a material adverse effect on HoustonStreet. Businesses may reject the Internet as a viable commercial medium for a number of reasons, including potentially inadequate network infrastructure, slow development of enabling technologies, insufficient commercial support or privacy concerns. The Internet's infrastructure may be unable to support the demands placed on it by increased usage. In addition, delays in developing or adopting new standards and protocols required to handle increased levels of Internet activity, or increased government regulation, could cause the Internet to lose its viability as a commercial medium.

Dependence on Trading Liquidity. HoustonStreet will need to achieve trading liquidity on its Internet-based wholesale energy trading exchange in order to increase and sustain revenues. If the volume and level of trades on the exchange do not increase, HoustonStreet will not achieve profitability.

Dependence on Increased Business from Unaffiliated Customers. If HoustonStreet fails to grow its customer base or generate repeat and expanded business from customers that are not affiliated with BayCorp, HoustonStreet will be unable to achieve or sustain profitability. For the period beginning July 8, 1999 through December 31, 1999, Great Bay, a subsidiary of BayCorp, was a party to 77% of all trades on HoustonStreet. HoustonStreet earns standard commissions from all trades on HoustonStreet, including trades by Great Bay

and its counterparties. To date, a substantial majority of HoustonStreet's revenue has been derived from commissions from trades involving Great Bay and its counterparties.

HoustonStreet's management expects that commissions from trades involving Great Bay and its counterparties will be a less significant portion of revenue in the future as the number of registered traders and the volume of trades increases. If trading volume does not increase as anticipated, HoustonStreet's revenue will not increase and HoustonStreet's business and financial results will be materially adversely affected.

Need for Expanded Sales and Marketing Operations. Expanded sales and marketing operations will be necessary to attract traders to HoustonStreet's trading exchange, to lengthen the time and frequency of service use, and to build the HoustonStreet community of users. If HoustonStreet's sales and marketing operations fail to register additional users and generate increased traffic on its Web site, the number of trades completed on the exchange may not increase. If the number, size and frequency of transactions do not increase, HoustonStreet will be unable to increase its revenues and HoustonStreet's business will not achieve profitability.

Need for Additional Financing. Based on current levels of operations and planned growth, HoustonStreet's management anticipates that the net proceeds of its stock sales in February and March 2000 and cash generated from operations will be sufficient to meet HoustonStreet's needs through approximately October 2000. If HoustonStreet requires additional funding or determines that it is appropriate to raise additional funding, HoustonStreet may be unable to raise additional funds. Further, any such funding may result in significant dilution to existing HoustonStreet stockholders, including BayCorp. The inability to obtain sufficient funds from operations and external sources when needed would have a material adverse effect on HoustonStreet's business, results of operations and financial condition.

Ability to Implement Business Strategy. The growth and expansion of HoustonStreet's business are expected to place significant demands on HoustonStreet's management, operational and financial resources. Successful implementation of HoustonStreet's business strategy will depend on a number of factors, including its ability to:

- offer an efficient and effective wholesale energy trading platform that meets industry needs,
- increase awareness of the HoustonStreet brand,
- continue to develop and upgrade the HoustonStreet Web site and related technology, operating software and capacity,
- attract more wholesale energy traders to the HoustonStreet Web Site, lengthen the time and frequency of service use, and build the HoustonStreet community of registered users, and
- attract, hire, integrate, retain and motivate qualified personnel.

There can be no assurance that HoustonStreet will be successful in the implementation of its business strategy.

Reliance on Strategic Relationships. HoustonStreet may be unable to implement its strategic growth plans without successfully identifying, forming, maintaining and enhancing strategic relationships, such as its strategic relationship with Equiva. HoustonStreet's ability to achieve significant future revenue growth will depend in part on adding new strategic partners. If HoustonStreet is unable to form or successfully develop additional strategic relationships, HoustonStreet may be unable to grow its revenues and HoustonStreet could be materially adversely affected.

International Expansion. If HoustonStreet cannot expand internationally, HoustonStreet may be unable to take advantage of the potential revenue associated with energy trading on a global level. While HoustonStreet's management believes that HoustonStreet can become profitable if its services are widely adopted by power traders in the United States, the global energy market represents a much larger source of revenue.

To be successful, HoustonStreet's management believes that HoustonStreet must expand its operations into international markets. International operations will subject HoustonStreet to a number of risks that may increase HoustonStreet's costs and require significant management attention. These risks include:

- difficulties and increased expenses associated with staffing and managing foreign operations,
- differing technology standards that may impede HoustonStreet's ability to integrate its trading platforms across international borders,
- reluctance or inability of energy traders abroad to accept Internet-based wholesale energy trading as a method of conducting business,
- changes in regulatory requirements,
- currency exchange rate fluctuations, and
- potentially adverse tax consequences, including restrictions on the repatriation of earnings.

Regulatory Risks and Privacy Concerns. As use of the Internet evolves, federal, state and foreign agencies could adopt regulations covering issues such as user privacy, content and taxation of products and services. If enacted, government regulations could limit the market for HoustonStreet's services.

In order to use HoustonStreet's trading exchange, traders must first register with HoustonStreet. The registration process requires that users provide certain information about themselves and the companies for which they trade. Although HoustonStreet collects this data only with the consent of a visitor, privacy concerns may cause visitors to resist registering to use the exchange. In addition, legislative or regulatory requirements may heighten privacy concerns. Other countries and political entities, such as the European Economic Community, have adopted legislation or regulatory requirements relating to privacy. The United States may adopt similar legislation or regulatory requirements. If privacy legislation is enacted or privacy concerns are not adequately addressed, HoustonStreet's business could be materially adversely affected.

Unpredictability of Future Revenues; Potential Fluctuation in Quarterly Operating Results. As a result of HoustonStreet's limited operating history and the emerging nature of the market for Internet-based trading of wholesale energy products, HoustonStreet is unable to forecast its revenues accurately. HoustonStreet expects to experience significant fluctuations in its future quarterly operating results due to a variety of factors, many of which are outside HoustonStreet's control. These factors include the demand for HoustonStreet's trading services, the introduction and market acceptance of new services in the industry, reductions in trading commissions or changes in how services are priced, and the amount and timing of operating costs and capital expenditures related to expanding HoustonStreet's business, operations and infrastructure. Quarterly results also can be affected by changes in the use of the Internet and electronic commerce, changes in governmental regulations, and changes in general economic conditions and economic conditions specifically related to the Internet and energy trading markets.

In addition, trading volumes can fluctuate due to the seasonal nature of the wholesale electricity trading market. Typically, there are substantial declines in the volume of wholesale electricity trading during the fourth quarter of the calendar year. Based on statistics published by the FERC, the amount of electricity traded in the United States in the fourth quarter of 1998 was approximately 50% less than amount traded in the third quarter of 1998. HoustonStreet's management believes that fourth quarter trading can be adversely affected by seasonal trading patterns, the inclination of some utilities, independent power producers and power marketers to maintain existing trading positions near year-end and other factors.

It is difficult to forecast the effect such factors, or the combination of any of these factors, would have on HoustonStreet's results of operations for any given fiscal quarter. HoustonStreet's management believes that HoustonStreet's quarterly revenues, expenses and operating results could vary significantly in the future and that period-to-period comparisons should not be relied on as indications of future performance.

System Maintenance and Protection. Unanticipated problems at the third-party facility that houses substantially all of HoustonStreet's computer and communications hardware systems could cause interruptions or delays in HoustonStreet's business, loss of data or render HoustonStreet unable to process wholesale

energy trades. Any such interruptions or delays at the facility would harm HoustonStreet's revenue and results of operations. In addition, these third-party systems and operations are vulnerable to damage or interruption from intentional malicious acts, fire, flood, power loss, telecommunications failure, break-ins, earthquake and similar events. HoustonStreet does not have a formal disaster recovery plan and does not carry business interruption insurance. In addition, the failure by the third-party facility to provide the data communications capacity required by HoustonStreet, as a result of human error, natural disaster or other operational disruptions, could result in interruptions in HoustonStreet's service. The occurrence of any or all of these events could harm HoustonStreet's reputation and brand and business.

Traders on the HoustonStreet.com may also be harmed by any system or equipment failures experienced by HoustonStreet. In that event, HoustonStreet's relationship with these traders may be adversely affected, HoustonStreet may lose traders, HoustonStreet's ability to attract new users may be adversely affected and HoustonStreet could be exposed to liability.

If users of HoustonStreet's trading platform suffer similar interruptions in their operations, for any of the reasons discussed above or for other reasons, HoustonStreet's business could also be adversely affected. In addition, if traders' computer systems suffer interruptions, the link to HoustonStreet's Web site could be severed and the traders' wholesale energy trades could be delayed or stopped.

Rapid Technological Change. To remain competitive, HoustonStreet must continue to enhance and improve its services. The Internet is characterized by rapid technological change, changes in user and customer requirements and preferences, frequent new product and service introductions embodying new technologies and the emergence of new industry standards and practices. HoustonStreet's success will depend, in part, on its ability to:

- develop leading Internet-based technologies useful for wholesale energy trading,
- enhance its existing services,
- develop new services and technology that address the increasingly sophisticated and varied needs of wholesale energy traders, and
- respond to technological advances and emerging industry standards and practices on a cost-effective and timely basis.

HoustonStreet would be materially adversely affected if it is unable, for technical, legal, financial or other reasons, to adapt in a timely manner to changing market conditions or customer requirements.

Intense Competition. Wholesale energy trading markets are dynamic and intensely competitive. Competition is likely to increase in the future as new companies enter the market and current competitors expand their products and services. See "Business — Internet-based Energy Trading and Information Business — Competition." Many of these potential competitors are likely to enjoy substantial competitive advantages, including:

- larger technical, production and marketing staffs,
- a more established presence in the wholesale energy trading community,
- greater brand recognition, and
- substantially greater financial, marketing, technical and other resources.

If HoustonStreet does not compete effectively or if it experiences pricing pressures, reduced margins or loss of market share resulting from increased competition, HoustonStreet's business would be materially adversely affected.

Dependence on Management and Need for New Personnel. HoustonStreet is, and for the foreseeable future will be, dependent upon the services of its directors, executive officers and key management personnel. HoustonStreet's future success depends on its ability to identify, attract, hire, train, retain and motivate highly skilled technical, managerial, marketing, sales and customer service personnel. The loss of the services of

current key personnel and the failure to hire new personnel could have a material adverse effect upon HoustonStreet's results of operations, product development efforts and ability to grow.

In particular, HoustonStreet plans to recruit and hire a new Chief Financial Officer and new Vice President of Technology in 2000. Competition for such personnel is intense and there can be no assurance that HoustonStreet can attract, assimilate or retain sufficiently qualified personnel. The failure to hire and retain a new Chief Financial Officer, Vice President of Technology and other necessary technical, managerial, marketing, sales and customer service personnel, would materially adversely affect HoustonStreet.

HoustonStreet does not currently have employment agreements in place and does not currently carry key man life insurance. Although HoustonStreet intends to purchase key man term life insurance on the life of Frank W. Getman Jr., its President and Chief Executive Officer, that insurance is not currently in place. HoustonStreet does not plan to purchase life insurance on the lives of any of its other key personnel.

Management of Growth. HoustonStreet expects to experience significant growth in its business operations. This growth will place a substantial strain on HoustonStreet's resources. HoustonStreet's need to manage its growth successfully will require it to implement appropriate operational, financial, accounting and management information systems and controls. HoustonStreet's failure to manage its growth effectively would have a material adverse effect on HoustonStreet.

Protection of Proprietary Rights. HoustonStreet's ability to compete depends significantly on the proprietary nature of its Web site technology as well as its patent applications. HoustonStreet has filed two patent applications to date. HoustonStreet seeks to protect its proprietary rights through a combination of patent, copyright and trade secret law and confidentiality agreements. However, there can be no assurance that a third party will not misappropriate or otherwise obtain access to HoustonStreet's proprietary technology or develop similar technology independently. Competitors may also be able to circumvent any patents that HoustonStreet obtains.

In recent years, there has been significant litigation in the United States involving patents and other intellectual property rights. HoustonStreet could incur substantial costs to prosecute or defend any intellectual property litigation. If HoustonStreet litigated to enforce its rights, it would be expensive, would divert management resources and may not be adequate to prevent the use of its intellectual property by third parties.

Potential Intellectual Property Infringement. While HoustonStreet currently is not aware that it infringes any other patents, it is possible that HoustonStreet's technology infringes patents held by third parties. If HoustonStreet were to be found infringing, the owner of the patent could sue HoustonStreet for damages, prevent HoustonStreet from making, selling or using the owner's patented technology or could impose substantial royalty fees for those privileges.

Item 7A. *Quantitative and Qualitative Disclosure About Market Risk.*

The Company does not believe that there is any material market risk exposure with respect to derivative or financial instruments that would require disclosure under this item.

Item 8. *Financial Statements and Supplementary Data.*

The response to this item is submitted in the response found under Item 14(a)(1) in this report.

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

Not Applicable.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

(a) Directors. The information with respect to directors required under this item is incorporated herein by reference to the section captioned "Election of Directors" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on May 25, 2000.

(b) Executive Officers. The information with respect to executive officers required under this item is incorporated by reference to Part I of the Report.

Item 11. ***Executive Compensation.***

The information required under this item is incorporated herein by reference to the sections entitled "Election of Directors — Compensation for Directors," "— Executive Compensation," "— Employment Agreements," "— Report of the Compensation Committee" and "— Stock Performance Graph" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on May 25, 2000.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

The information required under this item is incorporated herein by reference to the section entitled "Security Ownership of Certain Beneficial Owners and Management" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on May 25, 2000.

Item 13. ***Certain Relationships and Related Transactions.***

The information required under this item is incorporated herein by reference to the section entitled "Certain Relationships and Related Transactions" in the Company's Proxy Statement with respect to the Annual Meeting of Stockholders to be held on May 25, 2000.

PART IV

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

(a) *Documents filed as a part of this Form 10-K:*

1. *Financial Statements.* The Consolidated Financial Statements listed in the Index to Consolidated Financial Statements and Financial Statement Schedules are filed as part of this Annual Report on Form 10-K.

2. *Financial Statement Schedules.* The Financial Statement Schedules listed in the Index to Consolidated Financial Statements and Financial Statement Schedules are filed as part of this Annual Report on Form 10-K — *not applicable.*

3. *Exhibits.* The Exhibits listed in the Exhibit Index immediately preceding such Exhibits are filed as part of this Annual Report on Form 10-K.

(b) *Reports on Form 8-K:*

On December 3, 1999, the Company filed a Current Report on Form 8-K dated November 19, 1999 pursuant to which the Company reported that its subsidiary, Little Bay Power Corporation, completed its previously announced acquisition of Montaup Electric Company's 2.9% interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire.

INDEX TO FINANCIAL STATEMENTS

BAYCORP HOLDINGS, LTD.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
BayCorp Holdings, Ltd.

We have audited the accompanying consolidated balance sheets of BayCorp Holdings, Ltd. (a Delaware corporation) and its wholly-owned subsidiaries, as of December 31, 1999 and 1998, and the related consolidated statements of income and comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 1999. 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. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of BayCorp Holdings, Ltd. and its wholly-owned subsidiaries as of December 31, 1999 and 1998, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Boston, Massachusetts
February 4, 2000
(except for the matters
discussed in Note 13,
as to which the date is
March 27, 2000)

BAYCORP HOLDINGS, LTD.

CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	December 31, 1999	December 31, 1998
ASSETS:		
Current Assets:		
Cash & Cash Equivalents	$ 3,180	$ 2,559
Restricted Cash — Escrow	2,503	0
Short-term Investments, at market	381	9,496
Accounts Receivable	4,564	3,051
Materials & Supplies, net	4,611	3,633
Prepayments & Other Assets	3,162	3,177
Total Current Assets	18,401	21,916
Property, Plant, & Equipment and Fuel:		
Utility Plant Assets	121,043	112,325
Non-Utility Plant Assets	3,203	0
Total Property, Plant & Equipment	124,246	112,325
Less: Accumulated Depreciation	(16,331)	(12,785)
Net Property, Plant & Equipment	107,915	99,540
Nuclear Fuel	20,243	19,390
Less: Accumulated Amortization	(11,863)	(10,821)
Net Nuclear Fuel	8,380	8,569
Net Property, Plant & Equipment and Fuel	116,295	108,109
Other Assets:		
Decommissioning Trust Fund	24,483	10,329
Deferred Debits & Other	5	4
Total Other Assets	24,488	10,333
Total Assets	$159,184	$140,358
LIABILITIES AND STOCKHOLDERS' EQUITY:		
Current Liabilities:		
Accounts Payable and Accrued Expenses	$ 3,060	$ 394
Miscellaneous Current Liabilities	3,663	3,761
Total Current Liabilities	6,723	4,155
Operating Reserves:		
Decommissioning Liability	79,443	60,274
Miscellaneous Other	545	502
Total Operating Reserves	79,988	60,776
Other Liabilities & Deferred Credits	6,227	4,068
Commitments & Contingencies		
Stockholders' Equity:		
Common stock, $.01 par value Authorized — 20,000,000 shares; issued and outstanding — 8,457,800 at December 31, 1999 and 8,417,800 at December 31, 1998	84	84
Less: Treasury Stock — 225,800 shares, at cost	(1,629)	(1,629)
Additional paid-in capital	92,295	92,100
Accumulated Other Comprehensive Income	(3)	565
Accumulated Deficit	(24,501)	(19,761)
Total Stockholders' Equity	66,246	71,359
Total Liabilities and Stockholders' Equity	$159,184	$140,358

(The accompanying notes are an integral part of these consolidated statements.)

BAYCORP HOLDINGS, LTD.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
Years Ended December 31,
(Dollars in Thousands)

	1999	1998	1997
Operating Revenues	$ 45,761	$ 32,034	$ 26,642
Operating Expenses:			
Production	18,220	20,775	20,805
Transmission	872	880	857
Purchased Power	12,232	1,046	0
Unrealized Loss on Firm Energy Trading Contracts	806	0	0
Administrative & General	9,291	7,988	7,525
Depreciation & Amortization	4,110	3,656	3,508
Taxes other than Income	2,989	2,965	4,185
Total Operating Expenses	48,520	37,310	36,880
Operating Loss	(2,759)	(5,276)	(10,238)
Other (Income) Deductions:			
Interest and Dividend Income	(551)	(938)	(1,252)
Decommissioning Cost Accretion	3,320	2,873	2,663
Decommissioning Trust Fund Income	(755)	(613)	(470)
Other Deductions	126	171	36
Total Other Deductions	2,140	1,493	977
Loss Before Income Taxes and Accounting Change	(4,899)	(6,769)	(11,215)
Provision for Income Taxes	0	0	0
Loss Before Change in Accounting Principle	(4,899)	(6,769)	(11,215)
Cumulative Effect of Change in Accounting Principle, net of tax	159	0	0
Net Loss	(4,740)	(6,769)	(11,215)
Other Comprehensive Income (Expense), net of tax	(568)	449	264
Comprehensive Loss	$ (5,308)	$ (6,320)	$ (10,951)
Weighted Average Shares Outstanding	8,207,866	8,242,858	8,292,534
Basic and Diluted Net Loss Per Share	$ (0.58)	$ (0.82)	$ (1.35)

(The accompanying notes are an integral part of these consolidated statements.)

BAYCORP HOLDINGS, LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(Dollars in Thousands)

	Common Stock, $.01 Par Value		Less: Treasury Stock					
	Issued and outstanding Shares	Issued and outstanding Amount	Shares	Amount	Additional Paid-In Capital	Accumulated Other Comprehensive Income	Accumulated Deficit	Total Stockholders' Equity
Balance at December 31, 1996	8,417,800	$84	78,045	$ (633)	$92,100	$(148)	$ (1,777)	$89,626
Treasury Stock — 66,955 shares, at cost	—	—	66,955	(535)	—	—	—	(535)
Net Change in Unrealized Holding Gain	—	—	—	—	—	264	—	264
Financial Results, January 1 to December 31, 1997	—	—	—	—	—	—	(11,215)	(11,215)
Balance at December 31, 1997	8,417,800	84	145,000	(1,168)	92,100	116	(12,992)	78,140
Treasury Stock — 80,800 shares, at cost	—	—	80,800	(461)	—	—	—	(461)
Net Change in Unrealized Holding Gain	—	—	—	—	—	449	—	449
Financial Results, January 1 to December 31, 1998	—	—	—	—	—	—	(6,769)	(6,769)
Balance at December 31, 1998	8,417,800	84	225,800	(1,629)	92,100	565	(19,761)	71,359
Stock Options Exercised	40,000	—	—	—	195	—	—	195
Net Change in Unrealized Holding Gain (Loss)	—	—	—	—	—	(568)	—	(568)
Financial Results, January 1 to December 31, 1999	—	—	—	—	—	—	(4,740)	(4,740)
Balance at December 31, 1999	8,457,800	$84	225,800	$(1,629)	$92,295	$ (3)	$(24,501)	$66,246

(The accompanying notes are an integral part of these consolidated statements.)

BAYCORP HOLDINGS, LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Years Ended December 31,
(Dollars in Thousands)

	1999	1998	1997
Net cash flow from operating activities:			
Net Loss	$(4,740)	$(6,769)	$(11,215)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation	4,110	3,656	3,508
Amortization of nuclear fuel	4,032	4,104	4,010
Unrealized Loss on Energy Contracts	647	0	0
Decommissioning trust accretion	3,320	2,873	2,663
Decommissioning trust interest	(755)	(617)	(470)
(Increase) decrease in accounts receivable	(1,512)	(2,586)	2,463
(Increase) decrease in materials & supplies	(160)	4	124
(Increase) decrease in prepaids and other assets	31	(1,607)	(1,117)
Increase in accounts payable	2,123	124	140
Increase (decrease) in taxes accrued	0	0	(1,504)
Increase (decrease) in misc. current liabilities	226	2,167	(2,477)
Other	48	374	435
Net cash provided by (used in) operating activities	7,370	1,723	(3,440)
Net cash flows (used in) investing activities:			
Capital additions	(4,896)	(2,700)	(2,555)
Nuclear fuel additions	(1,999)	(4,314)	(1,970)
Purchase of additional Seabrook Project interest	(4,913)	0	0
Payments to decommissioning fund	(1,696)	(1,343)	(1,106)
Short term investments, net	9,063	6,384	(3,535)
Net cash used in investing activities	(4,441)	(1,973)	(9,166)
Net cash provided by financing activities:			
Stock Option Exercise	195	0	0
Reacquired capital stock	0	(461)	(535)
Net cash (used in) provided by financing activities	195	(461)	(535)
Net increase (decrease) in cash and cash equivalents	3,124	(711)	(13,141)
Cash and cash equivalents, beginning of period	2,559	3,270	16,411
Cash and cash equivalents, end of period	$ 5,683	$ 2,559	$ 3,270

(The accompanying notes are an integral part of these consolidated statements.)

BAYCORP HOLDINGS, LTD.

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 1999

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. The Company

BayCorp Holdings, Ltd. ("BayCorp" or the "Company") is a holding company incorporated in Delaware in 1996. BayCorp owns three subsidiaries: HoustonStreet Exchange, Inc. ("HoustonStreet"), Great Bay Power Corporation ("Great Bay") and Little Bay Power Corporation ("Little Bay"), each of which is wholly-owned as of December 31, 1999.

HoustonStreet developed and operates HoustonStreet.com, an Internet-based trading platform and information portal for wholesale energy traders. Currently, HoustonStreet offers an online trading exchange that allows utilities, independent power producers and power marketers to trade electricity over the Internet. HoustonStreet plans to develop and launch trading platforms for crude and refined products, natural gas and other energy-related commodities. HoustonStreet is also exploring opportunities to license its trading platform for use in other non-energy business-to-business markets.

HoustonStreet initially launched its Internet-based wholesale electricity trading exchange in the Northeast in July 1999. In September 1999, HoustonStreet launched electricity trading throughout the United States.

Great Bay and Little Bay are electric generating companies. Their principal asset is a combined 15% joint ownership interest in the Seabrook Nuclear Power Project in Seabrook, New Hampshire (the "Seabrook Project"). This ownership interest entitles the companies to approximately 174 megawatts of the Seabrook Project's power output. Great Bay and Little Bay are exempt wholesale generators ("EWGs") under the Public Utility Holding Company Act of 1935 ("PUHCA"). Unlike regulated public utilities, Great Bay and Little Bay have no franchise area or captive customers. The companies sell their power in the competitive wholesale power markets, including through HoustonStreet.com.

Great Bay was incorporated in New Hampshire in 1986 and was formerly known as EUA Power Corporation. Little Bay was incorporated in New Hampshire in 1998. Great Bay sells its share of the electricity output of the Seabrook Project in the wholesale electricity market, primarily in the Northeast United States. Little Bay sells its power solely to Great Bay under an intercompany agreement. Intercompany revenues are eliminated in consolidation. Neither BayCorp nor its subsidiaries have operational responsibilities for the Seabrook Project. Great Bay currently sells all but approximately 10 MW of its share of the Seabrook Project capacity in the wholesale short-term market. In addition to selling its owned generation, Great Bay purchases power on the open market for resale to third parties.

Great Bay became a wholly-owned subsidiary of BayCorp in a corporate reorganization that involved a merger of a newly formed wholly-owned subsidiary of BayCorp with and into Great Bay on January 24, 1997. The consolidated assets and liabilities of Great Bay and its subsidiaries immediately before the reorganization were the same as the consolidated assets and liabilities of BayCorp and its subsidiaries immediately after the reorganization. The new corporate structure enables BayCorp, either directly or through subsidiaries other than Great Bay and Little Bay, to engage in businesses that these subsidiaries would be prohibited from pursuing due to their status as EWG's under the PUHCA. BayCorp may in the future enter into new businesses or acquire existing businesses, both in energy related fields and possibly in unrelated fields.

On November 19, 1999, Little Bay purchased an additional 2.9% interest in the Seabrook Project from Montaup Electric Company for a purchase price of $3.2 million, plus approximately $1.7 million of certain prepaid items. See Footnote 1N.

The Seabrook Project is a nuclear-fueled, steam electricity, generating plant located in Seabrook, New Hampshire, which was originally planned to have two Westinghouse pressurized water reactors, Seabrook Unit 1 and Seabrook Unit 2 (each with a rated capacity of 1,150 megawatts), utilizing ocean water for

condenser cooling purposes. Seabrook Unit 1 entered commercial service on August 19, 1990. Seabrook Unit 2 has been canceled. Great Bay became a wholesale generating company when Seabrook Unit 1 commenced commercial operation on August 19, 1990. In 1993, the Company became an Exempt Wholesale Generator ("EWG") under the Energy Policy Act of 1992.

The Seabrook Project is owned by Great Bay, Little Bay and nine other utility companies, consisting of North Atlantic Energy Company, Connecticut Light and Power, The United Illuminating Company, Canal Electric Company, Massachusetts Municipal Wholesale Electric Company, New England Power Company, New Hampshire Electric Cooperative, Inc., Taunton Municipal Lighting Plant and Hudson Light & Power Department (together with Great Bay and Little Bay, the "Participants"). Great Bay, Little Bay and the other Participants are parties to the Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units (the "JOA") which establishes the respective ownership interests of the Participants in the Seabrook Project and defines their responsibilities with respect to the ongoing operation, maintenance and decommissioning of the Seabrook Project. In general, all ongoing costs of the Seabrook Project are divided proportionately among the Participants in accordance with their ownership interests in the Seabrook Project. Each Participant is only liable for its share of the Seabrook Project's costs and not liable for any other Participant's share as ownership interests in the Seabrook Project are several and not joint. Great Bay's and Little Bay's combined joint ownership interest of 15% is the third largest interest among the Participants, exceeded only by the approximately 40% interest held by Northeast Utilities and its affiliates and the 17.5% interest held by The United Illuminating Company.

Great Bay's business strategy is to utilize unit contingent and firm forward sales contracts to maximize the value of its and Little Bay's 174 MW power supply from the Seabrook Project. Traditionally, Great Bay sold most of its share of the Seabrook Project electricity output under unit contingent contracts. Under unit contingent contracts, Great Bay is obligated to provide the buyer with power only when the Seabrook Project is operating. In late 1998, Great Bay began to sell some of its electricity as firm power, which entitles the buyer to electricity whether or not the Seabrook Project is operating. Buyers pay a premium for firm power over unit contingent power because they can rely on uninterrupted electricity. In order to supply firm power during Seabrook unscheduled outages, Great Bay purchases power from the spot market during these outages and resells that power to its firm power customers. Spot market sales are subject to price fluctuations based on the relative supply and demand of electricity. As a result of spot market power price fluctuations, Great Bay has, and may in the future, have to purchase power at prices exceeding prices paid by Great Bay's firm power customers during outages. Although Great Bay bears the primary risk of these price fluctuations, Great Bay maintains insurance to protect Great Bay during periods of extreme price volatility, subject to certain deductibles and coverage limits. This insurance, provided by CIGNA and others, provides up to $30 million of coverage through May 2002.

As of March 17, 2000, BayCorp and its subsidiaries had 35 employees, including 26 at HoustonStreet, seven at BayCorp and two employees at Great Bay. Little Bay has no employees.

B. Regulation

Great Bay and Little Bay are subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC"), the Nuclear Regulatory Commission ("NRC"), the New Hampshire Public Utilities Commission ("NHPUC") and other federal and state agencies as to rates, operations and other matters. Great Bay's and Little Bay's cost of service, however, is not regulated. As such, Great Bay's and Little Bay's accounting policies are not subject to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation."

C. Use of Management Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and

liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

D. Utility Plant and Non-Utility Plant Assets

The costs of additions to utility plant and non-utility plant are recorded at original cost.

E. Depreciation

(i) Utility Plant

Utility plant is depreciated on the straight-line method at rates designed to fully depreciate all depreciable properties over the lesser of estimated useful lives or the Seabrook Project's remaining NRC license life, which expires in 2026.

Capital projects constituting retirement units are charged to electric plant. Minor repairs are charged to maintenance expense. When properties are retired, the original costs, plus costs of removal, less salvage, are charged to the accumulated provision for depreciation.

(ii) Non-Utility Plant Assets

Non-Utility plant assets are stated at cost less accumulated depreciation. Expenditures that significantly improve or extend the life of an asset are capitalized. The Company's subsidiary, HoustonStreet, capitalizes external software application development costs and costs for upgrades and enhancements to its systems that result in additional functionality in accordance with the American Institute of Certified Public Accountants Statement of Position 98-10, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use.* Maintenance and repairs are charged to expense when incurred. Depreciation is calculated on the straight-line basis over an estimated useful live of three years.

F. Amortization of Nuclear Fuel

The cost of nuclear fuel is amortized to expense based on the rate of burn-up of the individual assemblies comprising the total core. Great Bay and Little Bay also provide for the cost of disposing of spent nuclear fuel at rates specified by the United States Department of Energy ("DOE") under a contract for disposal between Great Bay and Little Bay, through their managing agent North Atlantic Energy Service Corporation ("NAESCO"), and the DOE.

Great Bay recorded the estimated cost of the final unspent nuclear fuel core, which is expected to be in place at the expiration of the Seabrook Project's NRC operating license, as part of Great Bay's original "Fresh Start" balance sheet.

G. Amortization of Materials and Supplies

Great Bay and Little Bay amortize to expense an amount designed to fully amortize the cost of the material and supplies inventory that is expected to be on hand at the expiration of the Plant's NRC operating license.

H. Decommissioning

Based on the Financial Accounting Standards Board's ("FASB") tentative conclusions, Great Bay and Little Bay have recognized as a liability their proportionate share of the present value of the estimated cost of Seabrook Project decommissioning. For Great Bay, the initial recognition of this liability was capitalized as part of the Fair Value of the Utility Plant at November 23, 1994. For Little Bay, the amount was provided for

in the purchase price allocation. New Hampshire enacted a law in 1981 requiring the creation of a state-managed fund to finance decommissioning of any units in the state. During April 1999, the Nuclear Decommissioning Finance Committee ("NDFC") issued an order that adjusted the decommissioning collection period and funding levels based on the NDFC's opinion that Seabrook's anticipated energy producing life was twenty-five years from the time it went into commercial operation. This is eleven years earlier than the service life established by Seabrook's NRC operating license. The order also updated Seabrook's decommissioning estimate to $565 million (in 2000 dollars.) Based on this estimate, the present value of Great Bay's and Little Bay's share of liability as of December 31, 1999 was approximately $79 million.

Great Bay and Little Bay accrete their share of the Seabrook Project's decommissioning liability. This accretion is a non-cash charge and recognizes their liability related to the closure and decommissioning of their nuclear plant in current year dollars over the licensing period of the plant. As a result of this accretion, Great Bay's share of the estimated decommissioning cost increased from $55.8 million as of December 31, 1997 to $60.3 million as of December 31, 1998 to $79.4 million as of December 31, 1999. The December 31, 1999 balance includes Little Bay's decommissioning liability of approximately $13 million based on an accretion schedule over the original license life of the plant and not the NDFC's life.

The Seabrook Project's decommissioning estimate and funding schedule is subject to review each year by the New Hampshire Nuclear Decommissioning Finance Committee ("NDFC"). This estimate is based on a number of assumptions. Changes in assumptions for such things as labor and material costs, technology, inflation and timing of decommissioning could cause these estimates to change, possibly materially, in the near term.

The Staff of the Securities and Exchange Commission ("SEC") has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations and joint owners in the financial statements of these entities. In response to these questions, the FASB agreed to review the accounting for nuclear decommissioning costs. On February 7, 1996, the FASB issued an Exposure Draft entitled "Accounting for Certain Liabilities Related to Closure and Removal of Long-Lived Assets." On February 17, 2000, the FASB issued a "Revision of Exposure Draft issued February 7, 1996, Proposed Statement of Financial Accounting Standards: Accounting for Obligations Associated with the Retirement of Long-Lived Assets." Great Bay and Little Bay's accounting for decommissioning is based on the FASB's original tentative conclusions. The proposed statement requires that an obligation associated with the retirement of a tangible long-lived asset be recognized as a liability when incurred, and that the amount of the liability resulting from (a) the passage of time and (b) revisions to either the timing or amount of estimated cash flows should also be recognized. The proposed statement also requires that, upon initial recognition of a liability for an asset retirement obligation, an entity capitalize that cost by recognizing an increase in the carrying amount of the related long-lived asset. Upon adoption, the proposed statement would be effective for financial statements issued for fiscal years beginning after June 15, 2001.

Great Bay and Little Bay, based on the initial exposure draft, have been recognizing a liability based on the present value of the estimated future cash outflows required to satisfy their obligations using a risk free rate. The proposed Statement requires the initial measurement of the liability to be based on fair value, where the fair value is the amount that an entity would be required to pay in an active market to settle the asset retirement obligation in a current transaction in circumstances other than a forced liquidation or settlement. Because in most circumstances, a market for settling asset retirement obligations does not exist, the FASB described an expected present value technique for estimating fair value. If the proposed Statement is adopted, Great Bay's and Little Bay's decommissioning liability and annual provision for decommissioning accretion could change relative to 1999. Great Bay and Little Bay have not quantified the impact, if any, that the revised exposure draft will have on their financial statements.

Funds collected by Seabrook for decommissioning are deposited in an external irrevocable trust pending their ultimate use. The earnings on the external trusts also accumulate in the fund balance. The trust funds are restricted for use in paying the decommissioning of Unit 1. The investments in the trust are available for sale. Great Bay and Little Bay have therefore reported their investment in trust fund assets at market value and any unrealized gains and losses are reflected in equity. There was an unrealized holding gain of $42,000 and $540,000 as of December 31, 1999 and 1998.

Although the owners of Seabrook are accumulating funds in an external trust to defray decommissioning costs, these costs could substantially exceed the value of the trust fund, and the owners, including Great Bay and Little Bay, would remain liable for the excess.

In January 1997 and July 1997, the NRC staff ruled that Great Bay did not satisfy the NRC definition of "electric utility." In January 1998, Great Bay filed a petition with the NRC seeking NRC approval of Great Bay's proposal to fund decommissioning obligations. Great Bay's petition also sought, in the alternative, an NRC permanent exemption from the obligation of Great Bay to comply with the NRC regulations applicable to non "electric utility" owners of interests in nuclear power plants. In June 1998, the New Hampshire State legislature enacted legislation that provides that in the event of a default by Great Bay on its payments to the decommissioning fund, the other Seabrook joint owners would be obligated to pay their proportional share of such default. As a result of the enactment of this legislation, the NRC staff found that Great Bay complies with the decommissioning funding assurance requirements. In July 1998, the staff of the NRC notified Great Bay of the staff's determination that Great Bay complies with the decommissioning funding assurance requirements under NRC regulations.

In response to the New Hampshire legislation, Great Bay agreed to make accelerated payments to the Seabrook decommissioning fund such that Great Bay will have contributed sufficient funds by the year 2015 to allow sufficient monies to accumulate, with no further payments by Great Bay to the fund, to the full estimated amount of Great Bay's decommissioning obligation by the time the current Seabrook operating license expires in 2026. Based on the currently approved funding schedule and Great Bay's accelerated funding schedule, Great Bay's decommissioning payments will be approximately $1.8 million in 2000 and escalate at 4% each year thereafter through 2015. Little Bay's share of decommissioning costs was prefunded by Montaup Electric Company, the owner of the 2.9% interest in the Seabrook Project that Little Bay acquired in November 1999. As part of that acquisition, Montaup Electric Company transferred approximately $12.4 million into Little Bay's decommissioning account, an irrevocable trust earmarked for Little Bay's share of Seabrook Plant decommissioning expenses.

On November 15, 1992, Great Bay, the Bondholder's Committee and the Predecessor's former parent, Eastern Utilities ("EUA") entered into a settlement agreement that resolved certain proceedings against EUA brought by the Bondholder's Committee. Under the settlement agreement EUA reaffirmed its guarantee of up to $10 million of Great Bay's future decommissioning costs of Seabrook Unit 1.

I. Operating Revenues

(i) Energy Revenues

Revenues are recorded on an accrual basis based on billing rates provided for in contracts and approved by FERC. During the year ended December 31, 1999, two customers accounted for 29% and 24% of total operating revenues. For the year ended December 31, 1998, three customers accounted for 28%, 17% and 12% of total operating revenues. For the year ended December 31, 1997, three customers accounted for 50%, 13% and 11% of total operating revenues.

(ii) Internet Revenues

HoustonStreet revenue consists of commissions for megawatt hours traded on HoustonStreet.com and is recognized once the trade has been agreed upon by both parties to the trade.

J. Taxes on Income

The Company accounts for taxes on income under the liability method required by Statement of Financial Accounting Standards No. 109.

K. Cash Equivalents and Short Term Investments

For purposes of the Statements of Cash Flows, the Company considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents. The carrying amounts approximate fair value because of the short-term maturity of the investments.

All other short-term investments with a maturity of greater than three months are classified as available for sale and reflected as a current asset at market value. Changes in the market value of such securities are reflected in equity. The unrealized holding loss on short-term investments was $44,000 as of December 31, 1999 and the unrealized holding gain on short-term investments was $24,000 as of December 31, 1998.

L. Seabrook Unit 2

Since the Seabrook Project was originally designed to consist of two generating units, Great Bay and Little Bay also own a 15% joint ownership interest in Seabrook Unit 2. Great Bay and Little Bay assign no value to Seabrook Unit 2 because on November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been canceled in 1984, voted to dispose of Unit 2. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. There were no material sales of Unit 2 assets in 1998 or 1999.

The Participants are considering plans regarding disposition of Seabrook Unit 2, but such plans have not yet been finalized and approved. Great Bay and Little Bay are unable to estimate the costs for which they will be responsible in connection with the disposition of Seabrook Unit 2. Because Seabrook Unit 2 was never completed or operated, costs associated with its disposition will not include any amounts for decommissioning. Great Bay and Little Bay currently pay their share of monthly expenses required to preserve and protect the value of the Seabrook Unit 2 components. Any sales of Unit 2 property or inventory are reflected in other income as gains on the sale or transfer of assets. Transfers of Unit 2 items to Unit 1 were done at the historical basis of Unit 2 property or components.

M. Seabrook Outage Costs

The Company's and Great Bay's and Little Bay's operating results and the comparability of these results on an interim and annual basis are directly impacted by the operations of the Seabrook Project, including the cyclical refueling outages (generally 18 months apart) as well as unscheduled outages. During outage periods at the Seabrook Project, Great Bay and Little Bay have no electricity for resale from the Seabrook Plant and consequently no related revenues. Therefore the impact of outages on the Company's and Great Bay's and Little Bay's results of operations and financial position are materially adverse.

Great Bay and Little Bay accrue for the incremental costs of the Seabrook Project's scheduled outages over the periods between those outages. However, Great Bay and Little Bay continue to expense the normal Seabrook operating and maintenance expenses as incurred. Therefore, the Company will incur losses during scheduled outage periods as a result of the combination of the lack of revenue and the recognition of normal recurring operation and maintenance costs as well as the continuing depreciation of the utility plant. At the Seabrook Project, a scheduled refueling outage began on March 27, 1999. Seabrook resumed full operating capacity on May 21, 1999. Great Bay's share of the incremental operations and maintenance costs was approximately $3.7 million.

N. Acquisitions

On November 19, 1999, BayCorp's wholly-owned subsidiary, Little Bay Power Corporation, purchased an additional 2.9% interest in the Seabrook Nuclear Power Project from Montaup Electric Company, a subsidiary of Eastern Utilities Associates. The purchase price was $3.2 million plus approximately $1.9 million for certain prepaid items, primarily nuclear fuel and capital expenditures. The purchase price was funded with existing cash. Little Bay allocated the purchase price based on the estimated fair value of the assets acquired and liabilities assumed. A summary of the components of the purchase price and the preliminary allocation is as follows:

	(000's)
Preliminary allocation of purchase price:	
Current assets	$ 1,005
Utility plant	3,890
Nuclear fuel	1,845
Liabilities assumed and other	(1,827)
	$ 4,913

In addition, Montaup prefunded the decommissioning liability associated with Little Bay's 2.9% share of Seabrook by transfering approximately $12.4 million into Little Bay's decommissioning account, an irrevocable trust earmarked for Little Bay's share of the Seabrook Plant decommissioning expenses. Little Bay recorded an asset, Decommissioning Trust Fund, for $12.4 million and a corresponding liability for the same amount. The purchase agreement required that a restricted cash-escrow account be established for $2.5 million to cover Little Bay's share of budgeted cash requirements for a six month period. This fund is to be used to pay Little Bay's share of Seabrook costs of operations and capital expenditures during periods of Seabrook shutdowns.

Little Bay sells its power solely to Great Bay under an intercompany agreement. Great Bay then sells the power purchased from Little Bay in the wholesale electricity market. The accompanying consolidated financial statements include the results of the acquisition since November 19, 1999. Intercompany amounts between Little Bay and Great Bay have been eliminated in consolidation.

O. Segment Information

The Company adopted Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information" ("SFAS No. 131"), in 1999 when HoustonStreet began operations. This statement establishes standards for the reporting of information about operating segments in annual and interim financial statements and requires restatement of prior year information. Operating segments are defined as components of an enterprise for which separate financial information is available that is evaluated regularly by the chief operating decision maker(s) in deciding how to allocate resources and in assessing performance. SFAS No. 131 also requires disclosures about products and services, geographic areas and major customers.

P. Earnings Per Share

Basic earnings (loss) per share is computed by dividing net earnings by the weighted number of common shares outstanding for all periods presented. Diluted earnings (loss) per share reflects the dilutive effect of shares under option plans, warrants and preferred stock. Potentially dilutive shares outstanding during the period have been excluded from dilutive earnings (loss) per share because their effect would be antidilutive.

Based on an average market price of common stock of $5.58 per share, for the year ended December 31, 1999, the following table reconciles the weighted average common shares outstanding to the shares used in the computation of the basic and diluted earnings per share outstanding.

	December 31, 1999
Weighted average number of common shares outstanding and used in basic and diluted EPS calculation	8,207,866
Shares under option plans, excluded in computation of diluted EPS due to antidilutive effects	3,341

There were no potentially dilutive shares outstanding during 1998 and 1997.

Q. Accumulated Other Comprehensive Income

Effective January 1, 1998, the Company adopted SFAS No. 130, "Reporting Comprehensive Income" which requires the Company to report the changes in shareholders' equity from all sources during the period other than those resulting from investments by shareholders (i.e., issuance or repurchase of common shares and dividends.) Although adoption of this standard has not resulted in any change to the historic basis of determination of earnings or shareholders' equity, the other comprehensive income components recorded under generally accepted accounting principles and previously included under the category "retained earnings" are displayed as "accumulated other comprehensive income" within the balance sheet. The composition of other comprehensive income is as follows:

	Unrealized Gains (Losses) on Securities	Accumulated Other Comprehensive Income
Twelve Months Ending 12/31/98		
Beginning Balance	$116,000	$116,000
1998 Change	449,000	449,000
December 31, 1998	565,000	565,000
1999 Change	(568,000)	(568,000)
December 31, 1999	$ (3,000)	$ (3,000)

R. Reclassifications

Certain reclassifications have been made in prior years' financial statements to conform to classifications and presentation used in the current year.

S. Principles of Consolidation

The consolidated financial statements include the accounts of all majority-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

2. NUCLEAR ISSUES

Like other nuclear generating facilities, the Seabrook Project is subject to extensive regulation by the NRC. The NRC is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health, safety, environmental and anti-trust matters.

The NRC has promulgated numerous requirements affecting safety systems, fire protection, emergency response planning and notification systems, and other aspects of nuclear plant construction, equipment and operation. Great Bay and Little Bay have been, and may be, affected to the extent of their proportionate shares by the cost of any such modifications to Seabrook Unit 1.

Nuclear units in the United States have been subject to widespread criticism and opposition. Some nuclear projects have been canceled following substantial construction delays and cost overruns as the result of licensing problems, unanticipated construction defects and other difficulties. Various groups have by litigation, legislation and participation in administrative proceedings sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste. In the event of a shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. The cost of such decommissioning, depending on the circumstances, could substantially exceed the owners' investment at the time of cancellation.

Public controversy concerning nuclear power could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

A. Nuclear Fuel

The Seabrook Project's joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. The Nuclear Waste Policy Act of 1982 (the "NWPA") requires the United States Department of Energy (the "DOE"), subject to various contingencies, to design, license, construct and operate a permanent repository for high level radioactive waste and spent nuclear fuel, which are collectively referred to as "high level waste."

The joint owners of the Seabrook Project, through their managing agent NAESCO, entered into contracts with the DOE for high level waste disposal in accordance with the NWPA. Under these contracts and the NWPA, the DOE was required to take title to and dispose of the Seabrook Project's high level waste beginning no later than January 31, 1998. However, the DOE has announced that its first high level waste repository will not be in operation until 2010 at the earliest.

As a result of this delay, many states and nuclear plant operators, including NAESCO, sued the DOE for injunctive relief and monetary damages. Two U.S. Courts of Appeals ordered the DOE to proceed with its high level waste disposal obligations and ruled that plant operators are entitled to money damages from DOE. However, there can be no assurance that the Seabrook Project will collect damages from the DOE because, among other things, NAESCO's case against the DOE is still pending.

In February 1999, the DOE proposed to Congress an alternative interim plan for high level waste management. The DOE proposed to take legal title and responsibility for the waste (on-site at nuclear plants such as Seabrook) until a permanent repository becomes available. Ultimately, Congress rejected that proposal, and on March 22, 2000, Congress passed amendments to the NWPA that would require the DOE to begin accepting nuclear waste shipments at a Nevada site in 2007. However, President Clinton stated he would veto this legislation and Congress is not expected to override Mr. Clinton's veto. Regardless of whether this legislation becomes law or alternative solutions are identified, nuclear plants such as Seabrook must retain high level waste on-site or make other storage provisions until the DOE begins receiving nuclear waste materials in accordance with the NWPA and its contracts.

The Seabrook Project increased its on-site storage capacity for low level waste ("LLW") in 1996 and that capacity is expected to be sufficient to meet the Project's storage requirements through 2006. In addition, the managing agent of the Seabrook Project has advised Great Bay that the Seabrook Project has adequate on-site storage capacity for high level waste until approximately 2010.

The Low-Level Radioactive Waste Policy Act of 1980 requires each state to provide disposal facilities for LLW generated within the state, either by constructing and operating facilities or by joining regional compacts with other states to jointly fulfill their responsibilities. However, the Low-Level Radioactive Waste Policy Amendments Act of 1985 permits each state in which a currently operating disposal facility is located (South

Carolina, Nevada and Washington) to impose volume limits and a surcharge on shipments of LLW from states that are not members of their regional compact.

In April 1995, a privately owned facility in Utah was approved as a disposal facility for certain types of LLW. The Seabrook Project began shipping certain LLW to the Utah facility in December 1995. In 1999, the Seabrook Project also began shipping some LLW to a privately owned facility in Tennessee. All LLW generated by the Seabrook Project that exceeds the maximum radioactivity level of LLW accepted by these facilities is currently stored on-site at the Seabrook facility.

B. Federal Department of Energy Decontamination and Decommissioning Assessment

Title XI of the Energy Policy Act of 1992 (the "Policy Act") provides for decontaminating and decommissioning of the Federal Department of Energy's ("DOE's") enrichment facilities to be partially funded by a special assessment against domestic utilities. Each utility's share of the assessment is to be based on its cumulative consumption of DOE enrichment services. As of December 31, 1999, the Company had accrued its pro rata estimated obligation of $636,000 related to the project's prior years' usage to be paid over the 15-year period beginning October 1, 1992.

C. Price Anderson Act

In accordance with the Price Anderson Act, the limit of liability for a nuclear-related accident is approximately $9 billion, effective November 18, 1994. The primary layer of insurance for this liability is $200 million of coverage provided by the commercial insurance market. The secondary coverage is approximately $9 billion, based on the approximately 106 currently licensed reactors in the United States. The secondary layer is based on a retrospective premium assessment of $83.9 million per nuclear accident per licensed reactor, payable at a rate not exceeding $10 million per year per reactor. In addition, the retrospective premium is subject to inflation based indexing at five year intervals and, if the sum of all public liability claims and legal costs arising from any nuclear accident exceeds the maximum amount of financial protection available, then each licensee can be assessed an additional 5% ($4.2 million) of the maximum retrospective assessment. With respect to the Seabrook Project, Great Bay and Little Bay would be obligated to pay its ownership share of any assessment resulting from a nuclear incident at any United States nuclear generating facility. Great Bay and Little Bay estimate their maximum liability per incident currently would be an aggregate amount of approximately $12.6 million per accident, with a maximum annual assessment of about $1.5 million per incident, per year.

In addition to the insurance required by the Price Anderson Act, the NRC regulations require licensees, including the Seabrook Project, to carry all risk nuclear property damage insurance in the amount of at least $1.06 billion, which amount must be dedicated, in the event of an accident at the reactor, to the stabilization and decontamination of the reactor to prevent significant risk to the public health and safety.

D. Nuclear Insurance

Insurance has been purchased by the Seabrook Project from Nuclear Electric Insurance Limited ("NEIL") to cover the costs of property damage, decontamination or premature decommissioning resulting from a nuclear incident and American Nuclear Insurance/Mutual Atomic Energy Liability Underwriters ("ANI") to cover workers' claims. All companies insured with NEIL and ANI are subject to retroactive assessments, if losses exceed the accumulated funds available to NEIL and ANI, respectively. The maximum potential assessment against the Seabrook Project with respect to losses arising during the current policy years are $26.4 million. The Company's liability for the retrospective premium adjustment for any policy year ceases six years after the end of that policy year unless prior demand has been made.

Great Bay and Little Bay also independently purchase business interruption insurance from Nuclear Electric Insurance Limited ("NEIL"). The current policy is in effect from April 1, 1999 until April 1, 2000 and a renewal policy has been signed which will be in effect from April 1, 2000 until April 1, 2001. The policy provides for the payment of a fixed weekly loss amount of $670,000 in the event of an outage at the Seabrook Project of more than 23 weeks resulting from the property damage occurring from a "sudden fortuitous event, which happens by chance, is unexpected and unforeseeable." The maximum amount payable to Great Bay and Little Bay is $90.6 million. Under the terms of the policy, Great Bay and Little Bay are subject to a potential retrospective premium adjustment of up to approximately $469,000 should NEIL's board of directors deem that additional funds are necessary to preserve the financial integrity of NEIL. Since NEIL was founded in 1980, there has been no retrospective premium adjustment; however, there can be no assurance that NEIL will not make retrospective adjustments in the future. The liability for this retrospective premium adjustment ceases six years after the end of the policy unless prior demand has been made.

3. TAXES ON INCOME

The following is a summary of the (benefit) provision for income taxes for the years ended December 31, 1999, 1998 and 1997:

	December 31, 1999	December 31, 1998	December 31, 1997
		(000's)	
Federal			
Current	$(3,426)	$(6,192)	$(8,081)
Deferred	3,426	6,192	8,081
	0	0	0
State			
Current	(817)	(1,476)	(1,927)
Deferred	817	1,476	1,927
	0	0	0
Total (benefit) provision	$ 0	$ 0	$ 0

Accumulated deferred income taxes consisted of the following at December 31, 1999 and 1998:

	1999	1998
	(000's)	
Assets		
Net operating loss carryforwards	$ 87,875	$ 81,794
Decommissioning expense	5,279	3,985
Unfunded pension expense	1,311	685
Accrued outage expense	105	1,076
Inventory	477	407
Other, net	827	576
Liabilities		
Utility plant	(30,298)	(24,457)
Accumulated deferred income tax asset	65,576	64,066
Valuation allowance	(65,576)	(64,066)
Accumulated deferred income tax asset, net	$ 0	$ 0

The total income tax provision set forth above represents 0% in the years ended December 31, 1999, 1998 and 1997. The following table reconciles the statutory federal income tax rate to those percentages:

	December 31, 1999	December 31, 1998	December 31, 1997
	(Dollars in Thousands)		
Loss before taxes	$(4,739)	$(6,769)	$(11,215)
Federal statutory rate	34%	34%	34%
Federal income tax benefit at statutory levels	(1,611)	(2,301)	(3,813)
Increase (Decrease) from statutory levels			
State tax net of federal tax benefit	(217)	(345)	(513)
Valuation allowance	1,917	2,721	4,442
Other	(89)	75	(116)
Effective federal income tax expense	$ 0	$ 0	$ 0

Valuation allowances have been provided against any deferred tax assets, net due to the limitations on the use of carryforwards, discussed below, and the uncertainty associated with future taxable income. The valuation allowance of $56,086,000 as of December 31, 1994, if subsequently recognized will be allocated directly to paid in capital.

For federal income tax purposes, as of December 31, 1999, the Company had net operating loss carry forwards ("NOLs") of approximately $225 million, which are scheduled to expire between 2005 and 2019. Because the Company has experienced one or more ownership changes, within the meaning of Section 382 of the Internal Revenue Code of 1986, as amended, an annual limitation is imposed on the ability of the Company to use $136 million of these carryforwards. The Company's best estimate at this time is that the annual limitation on the use of $136 million of the Company's NOLs is approximately $5.5 million per year. Any unused portion of the $5.5 million annual limitation applicable to the Company's restricted NOLs is available for use in future years until such NOLs are scheduled to expire. The Company's other $89 million of NOLs are not currently subject to such limitations.

4. CAPITAL EXPENDITURES

The Company's cash capital expenditures, including nuclear fuel, are estimated to be approximately $29 million in 2000 and to aggregate approximately $25 million for the years 2001 through 2002.

5. ENERGY MARKETING

The Company utilizes unit contingent and firm forward sales contracts to maximize the value of its 174 MW power supply from the Seabrook Project. As of December 31, 1999, the Company had forward sales commitments that extend to the end of 2000. As of December 31, 1998, the unrealized gain on these open positions was $159,000. The value of open positions was determined using exchange settlement prices or, if applicable, over the counter prices. The unrealized gain at December 31, 1998 was deferred.

Effective January 1, 1999, Great Bay adopted Emerging Issues Task Force Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities ("EITF 98-10"). EITF 98-10 requires energy trading contracts to be recorded at fair value on the balance sheet, with the changes in fair value included in earnings. The cumulative effect of the accounting change as of January 1, 1999 was to decrease net loss by $159,000, or $0.02 per weighted average common share and to recognize gains on net open firm purchase and sales commitments considered to be trading activity.

As of December 31, 1999, the Company had a net unrealized loss of approximately $647,000 recorded in accrued expenses. The net change in unrealized loss on trading activities as of December 31, 1999 was $806,000 and is included in the accompanying consolidated statement of income for 1999.

6. PURCHASED POWER AGREEMENTS

Great Bay is party to a purchased power agreement, dated as of April 1, 1993 (the "UNITIL Purchased Power Agreement"), with UNITIL Power ("UNITIL") that provides for Great Bay to sell to UNITIL approximately 10 MW of power. The UNITIL Purchased Power Agreement commenced on May 1, 1993 and runs through October 31, 2010. The current price of power under the UNITIL Purchased Power Agreement is 5.24 cents per kilowatt-hour ("kWh"). The price is subject to increase in accordance with a formula that provides for adjustments at less than the actual rate of inflation. UNITIL has an option to extend the UNITIL Purchased Power Agreement for an additional 12 years until 2022.

The UNITIL Purchased Power Agreement is front-end loaded whereby UNITIL pays higher prices, on an inflation adjusted basis, in the early years of the Agreement and lower prices in later years. The average price per kWh and the contract formula rate in the contract are fixed over the life of the contract, so that any excess cash received in the beginning of the contract will be returned by the end of the contract, provided the contract does not terminate early. The difference between revenue billed under each rate is recorded in a "Balance Account" which increased annually to $4.1 million in July 1998, and now decreases annually, reaching zero in July 2001. Therefore, contract revenue is recorded under Generally Accepted Accounting Principles and Emerging Issues Task Force Ruling 91-6 based on the contract rates and no liability for the "Balance Account" is recognized provided that it is not probable that the contract will terminate early. If the UNITIL Purchased Power Agreement terminates prior to its scheduled termination, and if at that time there is a positive amount in the Balance Account, Great Bay is obligated to refund that amount to UNITIL. Management believes it is not probable that either party will terminate this contract prior to the end of its initial term.

To secure the obligations of Great Bay under the UNITIL Purchased Power Agreement, including the obligation to repay UNITIL the amount in the Balance Account, the UNITIL Purchased Power Agreement grants UNITIL a mortgage on Great Bay's interest in the Seabrook Project. This mortgage may be subordinated to first mortgage financing of up to a maximum amount of $80,000,000. The UNITIL Power Purchase Agreement further provides that UNITIL's mortgage will rank pari passu with other mortgages that may hereafter be granted by Great Bay to other purchasers of power from Great Bay to secure similar obligations, provided that (i) the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest may not exceed $80,000,000, and (ii) the combined total of all second mortgages on the Seabrook Interest may not exceed the sum of (a) $80,000,000 less the total amount of Great Bay's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

7. PECO SERVICES AGREEMENT AND WARRANT AGREEMENT

Great Bay and PECO Energy Company ("PECO") entered into a Services Agreement as of November 3, 1995 (the "PECO Services Agreement"), pursuant to which PECO was appointed as Great Bay's exclusive agent to market and sell Great Bay's uncommitted portion of electricity generated by the Seabrook Project. In June 1998, Great Bay and PECO terminated the power marketing agreement between the companies and Great Bay paid PECO approximately $2.5 million. During the quarter ended June 30, 1998, Great Bay made an approximate $2.5 million charge to income for this expense. This expense is reflected in Administrative and General expenses in the accompanying Consolidated Statement of Income.

8. STOCK OPTION PLAN

On April 24, 1995, the Board of Directors of the Company established the 1995 Stock Option Plan (the "Plan"), which received shareholder approval at the Company's annual meeting on April 16, 1996. The purpose of the Plan is to secure for the Company and its shareholders the benefits arising from capital stock ownership by employees, officers and directors of, and consultants or advisors to, the Company who are expected to contribute to the Company's future growth and success. Options granted pursuant to the Plan may

be either incentive stock options meeting the requirements of Section 422 of the Internal Revenue Code or non-statutory options which are not intended to meet the requirements of Section 422. The maximum number of shares of Common Stock that may be issued and sold under the Plan is 600,000 shares. The Plan will be administered by the Board of Directors of the Company and may be modified or amended by the Board in any respect, subject to shareholder approval in certain instances.

The Company accounts for the plan under APB Opinion No. 25, under which no compensation cost has been recognized as the options are granted at Fair Market Value.

On December 3, 1998, the Board of Directors of the Company voted to reprice all of the outstanding options of the Company as the current options were "out of the money" and they no longer had the desired motivational effect or compensatory benefit for the employees. The repricing of the options was based on the current market value of the stock as of December 18, 1998. Simultaneously with the repricing, 139,583 of existing options were forfeited. In accordance with APB Opinion 25 (the "Opinion"), a renewal, a change in price, an extension of the period of exercisability, or any other significant modification of a stock right establishes a new measurement date as of the date of change in the same fashion as if a new option were granted.

Under the current interpretations of APB Opinion 25, as the repricing was done at fair market value on the new measurement date, no compensation expense has been recognized.

The Financial Accounting Standards Board (the "Board") has concluded its initial review of practice problems associated with the Opinion on accounting for stock issued to employees. The Board issued an Exposure Draft of a proposed interpretation of the Opinion in the first quarter of 1999. The proposed effective date would be the issuance date of the final interpretation, which is expected to be in 2000. If adopted, the interpretation will be applied prospectively but will cover events that occurred after December 15, 1998. There will be no effect on financial statements for the period prior to the effective date of the final interpretation.

Had compensation cost for the plan been determined consistent with FASB Statement No. 123, Accounting for Stock Based Compensation, the Company's net income and earnings per share would have been reduced to the following pro forma amounts.

		1999	1998	1997
			(Dollars in Thousands)	
Net Loss:	As Reported	$(4,740)	$(6,769)	$(11,215)
	Pro Forma	(5,146)	(7,050)	(11,414)
EPS:	As Reported	$ (0.58)	$ (0.82)	$ (1.35)
	Pro Forma	(0.63)	(0.86)	(1.38)

Because the Statement 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of that to be expected in future years. A summary of the Company's stock option plan at December 31, 1999, 1998 and 1997, and changes during the years then ended, is presented in the table and narrative below:

	1999		1998		1997	
	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price
Outstanding at beginning of year	417,417	$4.92	505,000	$ 8.05	445,000	$8.15
Granted	323,500	2.88 to 6.88	52,000	4.25 to 7.25	60,000	7.33
Exercised	(40,000)	4.90	—		—	
Forfeited	—		(139,583)	8.65	—	
Expired	—				—	
Outstanding at end of year	700,917	5.36	417,417	4.92	505,000	8.05
Exercisable at end of year	476,005	4.92	322,849	4.97	425,000	8.04
Weighted average fair value of options granted		$ 3.66		$ 1.29		$3.32

The 700,917 options outstanding at December 31, 1999 have exercise prices between $2.88 and $6.88, with a weighted average exercise price of $5.36, and a remaining weighted average contractual life of 5.8 years.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions used for grants in 1999, 1998 and 1997 respectively: weighted average risk-free interest rates of 5.5, 4.7 and 6.7 percent; expected dividend yields of 0 percent; weighted average expected lives of 7, 6.5 and 7 years; and expected volatility of 54, 31 and 31 percent, respectively.

In June 1999, HoustonStreet's Board of Directors approved HoustonStreet's 1999 Stock Incentive Plan, which provides for the grant of incentive and nonqualified stock options for the purchase of HoustonStreet's common stock by HoustonStreet's management, employees, consultants, advisors and directors of HoustonStreet. As of December 31, 1999, options to purchase an aggregate of 840,000 shares of HoustonStreet common stock, at a weighted average option exercise price of $0.87 per share were outstanding under this plan. HoustonStreet has elected to account for its stock-based compensation plan under APB No 25. Had compensation cost related to the HoustonStreet options been determined, based on the fair value of the options at the grant date consistent with the provisions of SFAS No. 123, the effect on the 1999 consolidated net loss would not have been material.

9. NEW ACCOUNTING PRONOUNCEMENTS

In June 1998, the FASB issued SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS 133"). SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

SFAS 133, as amended by SFAS 137, will be effective for all fiscal quarters of all fiscal years beginning after June 15, 2000. A company may also implement SFAS 133 as of the beginning of any fiscal quarter after issuance (that is, fiscal quarters beginning June 16, 1998 and thereafter.) SFAS 133 cannot be applied retroactively. SFAS 133 must be applied to (a) derivative instruments and (b) certain derivative instruments

embedded in hybrid contracts that were issued, acquired, or substantively modified after December 31, 1997 (and, at the company's election, before January 1, 1998.)

The Company has not yet quantified the impact of adopting SFAS 133 on its financial statements and has not determined the timing of or method of adoption of SFAS 133. However, SFAS 133 could increase volatility in earnings and other comprehensive income.

10. PROPERTY TAXES

For each of the tax years 1994, 1995, 1996, 1997 and 1998, Great Bay filed property tax abatement applications with the towns of Hampton and Hampton Falls. The abatement requests were denied. Great Bay filed appeals for each of those years with the New Hampshire Board of Tax and Land Appeals (the "BTLA"). On November 11, 1999, Great Bay reached agreements settling the property tax litigation. As a result of the settlement agreement, Great Bay received $146,450 from the Town of Hampton and $21,967 from the Town of Hampton Falls. With regard to Hampton Falls, the settlement established an assessed valuation of $7,000,000 for 1999 and $2,500,000 for 2000. With regard to the Town of Hampton, the settlement established an assessed valuation of $20,000,000 for 1999 and $15,000,000 for 2000.

11. SEGMENT INFORMATION

As mentioned in Note 1, BayCorp is a holding company for Great Bay, Little Bay and HoustonStreet Exchange. The Company operates primarily in two segments, each of which is managed separately because each segment sells distinct products and services. Great Bay and Little Bay constitute the electric generating companies segment, whose principal asset is a combined 15% joint ownership interest in the Seabrook Nuclear Power Project and sell their combined power in the competitive wholesale power markets. HoustonStreet operates a Web portal for trading wholesale electric power and charges commissions for megawatt hours traded on its site HoustonStreet.com.

Management utilizes more than one measurement and multiple views of data to measure segment performance and to allocate resources to the segments. However, the dominant measurements are consistent with the company's consolidated financial statements and, accordingly, are reported on the same basis herein. Management evaluates the performance of its segments and allocates resources to them primarily based on cash flows and overall economic returns. Intersegment sales are generally accounted for at amounts comparable to sales to unaffiliated customers and are eliminated in consolidation. The accounting policies of the segments are described in the summary of significant accounting policies, in Note 1.

As of and for the Years Ended December 31 (000's)	Great Bay and Little Bay	HoustonStreet	Corporate	Eliminations	Total
1999					
Revenues	$ 46,381	$ 59	$ 2,449	$ (3,128)	$ 45,761
Depreciation & amortization	3,744	286	80	—	4,110
Operating Expenses	46,378	3,351	1,761	(2,970)	48,520
Interest expense	16	97	—	—	113
Segment net income (loss)	(2,096)	(3,397)	753	—	(4,740)
Total Assets	165,862	2,984	7,592	(17,254)	159,184
Capital expenditures	1,797	3,099	—	—	4,896
1998					
Revenues	$ 32,034	—	$ 1,920	$ (1,920)	$ 32,034
Depreciation & amortization	3,633	—	23	—	3,656
Operating Expenses	35,447	—	3,783	(1,920)	37,310
Interest expense	10	—	—	—	10
Segment net income (loss)	(7,489)	—	720	—	(6,769)
Total assets	138,086	—	71,442	(69,170)	140,358
Capital expenditures	2,700	—	—	—	2,700
1997					
Revenues	$ 26,642	—	$ 1,756	$ (1,756)	$ 26,642
Depreciation & amortization	3,494	—	14	—	3,508
Operating Expenses	37,501	—	1,134	(1,755)	36,880
Interest expense	(255)	—	—	—	(255)
Segment net income (loss)	(11,825)	—	610	—	(11,215)
Total assets	138,116	—	78,251	(76,209)	140,158
Capital expenditures	2,555	—	—	—	2,555

12. COMMITMENTS AND CONTINGENCIES

BayCorp and its wholly owned subsidiaries currently lease office space under noncancelable operating leases. Rental expense under operating lease agreements as of December 31, 1999 was $96,500.

Future minimum commitments for operating leases as of December 31, 1999 are as follows:

Year Ending	Operating Leases
December 31, 2000	$170,000
December 31, 2001	70,000
December 31, 2002	70,000
December 31, 2003	35,000
Total	$345,000

13. SUBSEQUENT EVENTS

In January 2000, BayCorp issued 15,800 of its incentive stock options to its employees and directors at an exercise price of $12.6875 per share. In January 2000, HoustonStreet issued 474,300 of its incentive stock options to its employees and directors at an exercise price of $2.75 per share.

In February 2000, HoustonStreet sold $6.0 million of its common stock and Series A preferred stock to Equiva Trading Company ("Equiva"). Equiva is a hydrocarbon supply and trading partnership jointly-owned by Equilon Enterprises LLC ("Equilon") and Motiva Enterprises LLC ("Motiva"). Equilon is owned by Shell Oil Company and Texaco Inc. Motiva is owned by Shell Oil Company, Texaco Inc. and Saudi Refining Inc., an affiliate of Saudi Aramco.

Also in February 2000, HoustonStreet announced plans to launch one of the first Web exchanges for wholesale crude oil and refined products trading. At that time, HoustonStreet entered into agreements with Equiva under which Equiva will share its knowledge of the oil trading industry with HoustonStreet and will pay HoustonStreet at least $1.5 million over the next two years as minimum trading commissions generated through Equiva's use of HoustonStreet's crude and refined oil products trading exchange, once it is created and operated.

In addition to sales of its capital stock to Equiva, HoustonStreet sold $10.6 million of its capital stock in February and March 2000 to other investors including Williams Energy Marketing & Trading Company, Omega Advisors, Inc., Elliott Associates, L.P., Thomas H. Lee Company and Sapient Corporation. Collectively with Equiva and Williams, HoustonStreet raised $16.6 million in gross proceeds through these stock sales. As a result, BayCorp owns approximately 53% of HoustonStreet's capital stock (on an as converted to common stock basis) as of March 27, 2000.

Sapient Corporation has been assisting HoustonStreet in designing and building its Internet site since inception. For the period from inception to December 31, 1999, HoustonStreet has recorded $2.4 million of such costs.

Omega Advisors, Inc. and its related investment partnerships who beneficially own approximately 33.2% of BayCorp, purchased HoustonStreet Series A Preferred Stock and own, directly and indirectly, approximately 21.26% of HoustonStreet as of March 27, 2000, assuming conversion of the HoustonStreet Series A preferred stock to HoustonStreet common stock at a conversion rate of one to one.

Elliot Associates, L.P. and its related partnerships who beneficially own approximately 24.3% of BayCorp, purchased HoustonStreet Series A Preferred Stock and own, directly or indirectly, approximately 16.55% of HoustonStreet, as of March 27, 2000, assuming conversion of the HoustonStreet Series A preferred stock to HoustonStreet common stock at a conversion rate of one to one.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BAYCORP HOLDINGS, LTD.

March 28, 2000

By: /s/ FRANK W. GETMAN JR.
Frank W. Getman Jr.
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ FRANK W. GETMAN JR. Frank W. Getman Jr.	President, Chief Executive Officer and Director (principal executive officer, principal financial officer and principal accounting officer)	March 28, 2000
/s/ KENNETH A. BUCKFIRE Kenneth A. Buckfire	Director	March 28, 2000
/s/ STANLEY I. GARNETT Stanley I. Garnett	Director	March 28, 2000
/s/ MICHAEL R. LATINA Michael R. Latina	Director	March 28, 2000
/s/ LAWRENCE M. ROBBINS Lawrence M. Robbins	Director	March 28, 2000
/s/ JOHN A. TILLINGHAST John A. Tillinghast	Director	March 28, 2000

EXHIBIT INDEX

Exhibit Number	Description of Exhibit
3.1	Certificate of Incorporation of BayCorp Holdings, Ltd.(1)
3.2	By-laws of BayCorp Holdings, Ltd.(1)
10.1	Agreement Between Bangor Hydro-Electric Company, Central Maine Power Company, Central Vermont Public Service Corporation, Fitchburg Gas and Electric Light Company, Maine Public Service Company and EUA Power Corporation relating to use of certain transmission facilities, dated October 20, 1986.(2)
10.2	Limited Guaranty by Eastern Utilities Associates of Decommissioning Costs in favor of Joint Owners of the Seabrook Project, dated May 5, 1990.(2)
10.3	Composite Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, as amended, dated November 1, 1990.(2)
10.4	Seventh Amendment to and Restated Agreement for Seabrook Project Disbursing Agent as amended through and including the Second Amendment, by and among North Atlantic Energy Service Corporation, Great Bay Power Corporation and other Seabrook Project owners, dated November 1, 1990.(2)
10.5	Seabrook Project Managing Agent Operating Agreement by and among the North Atlantic Energy Service Corporation, Great Bay Power Corporation and parties to the Joint Ownership Agreement, dated June 29, 1992.(2)
10.6	Settlement Agreement by and among EUA Power Corporation, Eastern Utilities Associates and the Official Bondholders' Committee, dated November 18, 1992.(2)
10.7	Purchased Power Agreement between UNITIL Power Corporation and Great Bay Power Corporation, dated April 26, 1993.(2)
10.8	Power Purchase Option Agreement between UNITIL Power Corporation and Great Bay Power Corporation, dated December 22, 1993.(2)
10.9	Second Mortgage and Security Agreement between UNITIL Power Corporation and Great Bay Power Corporation, dated December 22, 1993.(2)
10.10	Third Mortgage and Security Agreement between UNITIL Power Corporation and Great Bay Power Corporation, dated December 22, 1993.(2)
10.11	Registration Rights Agreement between Great Bay Power Corporation and the Selling Stockholders, dated April 7, 1994.(2)
10.12	Amendment to Registration Rights Agreement between Great Bay Power Corporation and the Selling Stockholders, dated November 23, 1994.(2)
10.13	Stock and Subscription Agreement among Great Bay Power Corporation and the Selling Stockholders, dated April 7, 1994.(2)
10.14	Acknowledgement and Amendment to Stock and Subscription Agreement, dated November 23, 1994.(2)
10.15	Settlement Agreement by and among Great Bay Power Corporation, the Official Bondholders' Committee and the Selling Stockholders, dated September 9, 1994.(2)
10.16	Letter Agreement, dated December 20, 1994, between Great Bay Power Corporation and the Selling Stockholders amending Registration Rights Agreement, as previously amended on November 23, 1994.(2)
10.17	Letter Agreement, dated March 29, 1995, between Great Bay Power Corporation and the Selling Stockholders amending Registration Rights Agreement, as previously amended on November 23, 1994 and December 20, 1994.(2)
10.18	1996 Stock Option Plan of BayCorp Holdings, Ltd.(1)(4)
10.19	Employment Agreement between Frank W. Getman Jr. and BayCorp Holdings, Ltd., dated May 5, 1998.(4)(5)
10.20	Employment Agreement between John A. Tillinghast and BayCorp Holdings, Ltd., dated May 5, 1998.(4)(5)
10.21	Incentive Stock Option Agreement, dated as of August 1, 1995, by and between Frank W. Getman Jr. and Great Bay Power Corporation.(4)(6)
10.22	Incentive Stock Option Agreement, dated as of September 17, 1996, by and between Frank W. Getman Jr. and Great Bay Power Corporation.(4)(7)

Exhibit Number	Description of Exhibit
10.23	Incentive Stock Option Agreement, dated as of April 24, 1995, by and between John A. Tillinghast and Great Bay Power Corporation.(4)(6)
10.24	1999 Stock Incentive Plan of HoustonStreet Exchange, Inc.(4)(8)
10.25	Amended and Restated Incentive Stock Option Agreement, dated as of July 30, 1999, by and between Frank W. Getman Jr. and HoustonStreet Exchange, Inc. (first of two identically titled and dated agreements).(4)(8)
10.26	Amended and Restated Incentive Stock Option Agreement, dated as of July 30, 1999, by and between Frank W. Getman Jr. and HoustonStreet Exchange, Inc. (second of two identically titled and dated agreements).(4)(8)
10.27	Asset Purchase Agreement by and between Montaup Electric Company and Great Bay Power Corporation, dated as of June 24, 1998.(9)
10.28	Assignment by and between Great Bay Power Corporation and Little Bay Power Corporation dated as of August 28, 1998.(10)
10.29	Escrow Agreement by and between Little Bay Power Corporation and Citizens Bank New Hampshire dated November 10, 1999.(10)
10.30	Series A Convertible Preferred Stock Purchase Agreement dated as of February 2, 2000, as amended, by and among HoustonStreet Exchange, Inc. and the Purchasers (as defined therein).(8)
10.31	Amended and Restated Stockholders' Voting Agreement dated as of March 6, 2000 by and among BayCorp Holdings, Ltd. and the Purchasers (as defined therein).(8)
10.32	Investor Rights Agreement dated as of February 2, 2000, as amended, by and among HoustonStreet Exchange, Inc., BayCorp Holdings, Ltd. and the Purchasers (as defined therein).(8)
10.33	Rights of First Refusal and Co-Sale Agreement dated as of February 2, 2000, by and among HoustonStreet Exchange, Inc. and the Purchasers (as defined therein).(8)
10.34	Form of Omnibus Signature Page dated as of March 6, 2000 relating to the four preceding exhibits.(8)
10.35	Incentive Stock Option Agreement, dated July 30, 1999, by and between Frank W. Getman Jr. and BayCorp Holdings, Ltd.(4)(8)
21.1	List of Subsidiaries of BayCorp Holdings, Ltd.(8)
23.1	Consent of Arthur Andersen LLP.(8)

(1) Filed as an exhibit to the Registration Statement on Form S-4 of BayCorp Holdings, Ltd. (Registration Statement 333-3362) filed on July 12, 1996 and incorporated herein by reference.

(2) Filed as an exhibit to the Registration Statement on Form S-1 of Great Bay Power Corporation (Registration No. 33-88232) declared effective on April 17, 1995 and incorporated herein by reference.

(3) Filed as an exhibit to the Quarterly Report on Form 10-Q of BayCorp Holdings, Ltd. for the quarter ended July 30, 1998 (File No. 1-12527) on August 13, 1998 and incorporated herein by reference.

(4) Management contract or compensation plan or arrangement required to be filed as an exhibit pursuant to Item 14(c) of Form 10-K.

(5) Filed as an exhibit to the Company's Annual Report on Form 10-K (File No. 1-12527) on March 31, 1999 and incorporated herein by reference.

(6) Filed as an exhibit to the Quarterly Report on Form 10-Q of Great Bay Power Corporation for the quarter ended March 31, 1995 (File No. 0-25748) on May 9, 1995 and incorporated herein by reference.

(7) Filed as an exhibit to the Company's Annual Report on Form 10-K (File No. 1-12527) on March 26, 1997 and incorporated herein by reference.

(8) Filed as an exhibit to this Annual Report on Form 10-K.

(9) Filed as an exhibit to the Quarterly Report on Form 10-Q of BayCorp Holdings, Ltd. for the quarter ended June 30, 1998 (File No. 1-12527) on August 13, 1998 and incorporated herein by reference.

(10) Filed as an exhibit to the Current Report on Form 8-K of BayCorp Holdings, Ltd. (File No. 1-12527) dated November 19, 1999 and filed on December 3, 1999 and incorporated herein by reference.

BOARD OF DIRECTORS

John A. Tillinghast
Chairman of the Board

Kenneth A. Buckfire
Managing Director,
Wasserstein Perella & Co., Inc

Stanley I. Garnett
Senior Advisor,
PHB Hagler Bailly

Frank W. Getman Jr.
President and Chief Executive Officer,
BayCorp Holdings, Ltd.

Michael R. Latina
Portfolio Manager,
Elliott Associates, L.P.

Lawrence M. Robbins
General Partner,
Omega Advisors, Inc.

OFFICERS

Frank W. Getman Jr.
President,
Chief Executive Officer
and Secretary

CORPORATE COUNSEL

Hale and Dorr LLP
60 State Street
Boston, Massachusetts 02109

TRANSFER AGENT

American Stock Transfer and Trust Company
40 Wall Street
New York, New York 10005

INDEPENDENT AUDITORS

Arthur Andersen LLP
225 Franklin Street
Boston, Massachusetts 02110

CORPORATE OFFICES
20 International Drive, Suite 301
Portsmouth, New Hampshire 03801-6809

ANNUAL MEETING

The Annual Meeting of Stockholders will be held on May 25, 2000 at 1:00 p.m. EST at the offices of the American Stock Exchange, 86 Trinity Place, New York, New York.

FORM 10-K

For a copy of the Form 10-K Annual Report filed with the Securities and Exchange Commission, write to the Company's Corporate Offices or call (603) 431-6600.

STOCK INFORMATION

The Company's stock is listed on the American Stock Exchange under the symbol "MWH'.

Printed on Recycled Paper

Goulet, Salvidio & Associates, P.C.
Certified Public Accountants

HUDSON LIGHT AND POWER DEPARTMENT

Financial Statements

December 31, 1999 and 1998

HUDSON LIGHT AND POWER DEPARTMENT
TABLE OF CONTENTS
DECEMBER 31, 1999 and 1998

Goulet, Salvidio & Associates, P.C.
Certified Public Accountants

James F. Goulet, CPA, MST
Catherine A. Kuzmeskus, CPA

Michael A. Salvidio, CPA
James R. Dube, CPA

INDEPENDENT AUDITORS' REPORT

The Board of Commissioners
Hudson Light and Power Department

We have audited the accompanying financial statements of Hudson Light and Power Department of Hudson, Massachusetts, as of and for the years ended December 31, 1999 and 1998 as listed in the table of contents. These financial statements are the responsibility of the Department's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As discussed in Note 5 to the financial statements, the Department records pension expense based on a formula determined by the Town of Hudson and an additional contribution based on a percentage determined by an independent actuarial study, whereas generally accepted accounting principles require the use of actuarial methods in determining annual pension expense and certain disclosures required by the Governmental Accounting Standards Board relating to pensions have been omitted. The effect on the financial statements of not using actuarial methods has not been determined.

In our opinion, except for the effects of such adjustments, if any, as might have been determined to be necessary had we used the independent actuarial study to determine pension expense and the omission of certain pension plan disclosures required by the Governmental Accounting Standards Board on the 1999 and 1998 financial statements, the financial statements referred to above present fairly, in all material respects, the financial position of the Hudson Light and Power Department as of December 31, 1999 and 1998, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Goulet, Salvidio & Associates, P.C.

Goulet, Salvidio + Associates, P.C.

Worcester, Massachusetts
May 14, 2000

Nine Irving Street · Worcester, MA 01609 · Tel: 508-757-5957 · Fax: 508-753-0948 · E-mail: gsamycpa@aol.com

HUDSON LIGHT AND POWER DEPARTMENT
BALANCE SHEETS
OPERATING FUND
DECEMBER 31, 1999 and 1998

ASSETS

	1999	1998
UTILITY PLANT:		
Intangible Plant	$ 3,880	$ 3,880
Production Plant	7,008,650	7,003,452
Nuclear Fuel	313,998	307,877
Transmission Plant	1,644,305	1,644,305
Distribution Plant	9,998,050	9,848,007
General Plant	2,161,843	2,045,570
	21,130,726	20,853,091
Less: Accumulated Depreciation	15,220,261	14,868,315
Net Utility Plant	5,910,465	5,984,776
OTHER PROPERTY AND INVESTMENTS:		
Funds on Deposit with Town Treasurer		
Depreciation Fund	126,073	86,029
Depreciation Investment Fund	3,692,521	3,645,209
Investment	105,987	115,983
Total Other Property and Investments	3,924,581	3,847,221
CURRENT ASSETS:		
Funds on Deposit with Town Treasurer		
Operating Fund	4,975,604	5,532,756
Customer Deposits	282,344	247,137
Customer Deposits-Interest	153,139	134,199
Petty Cash	500	500
Customer Accounts Receivable	2,028,834	2,749,543
Other Receivables	430,933	211,499
Due from Rate Stabilization Fund	949,983	0
Deferred Debit-Fuel Charge	0	229,705
Materials and Supplies	854,753	754,719
Purchased Power Prepayments	174,968	197,533
Purchased Power Working Capital	340,076	338,152
Total Current Assets	10,191,134	10,395,743
TOTAL ASSETS	$ 20,026,180	$ 20,227,740

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
BALANCE SHEETS
OPERATING FUND
DECEMBER 31, 1999 and 1998

CAPITALIZATION AND LIABILITIES

	1999	1998
CAPITALIZATION:		
Contributions in Aid of Construction	$ 428,752	$ 428,752
Appropriated Retained Earnings-Bond Repayments	1,925,000	1,925,000
Unappropriated Retained Earnings	15,058,731	14,652,489
Total Capitalization	17,412,483	17,006,241
CURRENT LIABILITIES:		
Accounts Payable	777,797	2,004,236
Customer Deposits	325,823	247,228
Customer Deposits-Interest	152,376	133,436
Tax Collections Payable	13,405	15,779
Miscellaneous Current and Accrued Liabilities	401,147	210,533
Deferred Credit - Fuel Charge	332,862	0
Total Current Liabilities	2,003,410	2,611,212
OTHER NONCURRENT LIABILITIES:		
Accumulated Provision for Insurance	605,394	605,394
DEFERRED CREDITS:		
Customer Advances for Construction	2,100	2,100
Deferred Credits-Other	2,793	2,793
Total Deferred Credits	4,893	4,893
TOTAL CAPITALIZATION AND LIABILITIES	$ 20,026,180	$ 20,227,740

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
BALANCE SHEETS
DECEMBER 31, 1999 and 1998

RATE STABILIZATION TRUST FUND

ASSETS

	1999	1998
OTHER PROPERTY AND INVESTMENTS:		
Funds on Deposit with Town Treasurer		
Rate Stabilization Trust Fund	$ 8,037,854	$ 9,680,755

CAPITALIZATION AND LIABILITIES

	1999	1998
CAPITALIZATION:		
Appropriated Retained Earnings for Rate Stabilization Trust Fund	$ 7,087,871	$ 9,680,755
LIABILITIES:		
Due to Operating Fund	949,983	0
TOTAL CAPITALIZATION AND LIABILITIES	$ 8,037,854	$ 9,680,755

RETIREMENT TRUST FUND

ASSETS

	1999	1998
OTHER PROPERTY AND INVESTMENTS:		
Funds on Deposit with Town Treasurer		
Retirement Trust Fund	$ 6,345,707	$ 6,324,434

CAPITALIZATION

	1999	1998
CAPITALIZATION		
Appropriated Retained Earnings for Retirement Trust Fund	$ 6,345,707	$ 6,324,434

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
STATEMENTS OF INCOME AND UNAPPROPRIATED RETAINED EARNINGS
OPERATING FUND
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

	1999	1998
OPERATING REVENUES	$ 26,456,236	$ 27,374,302
OPERATING EXPENSES:		
Production Expenses	752,424	621,322
Purchased Power Expenses	21,006,992	22,010,629
Transmission Expenses	1,502,955	1,743,718
Distribution Expenses	616,432	603,499
General Expenses	1,709,962	1,453,461
Real Estate and Other Taxes	23,610	25,131
Depreciation Expense	614,423	604,299
Total Operating Expenses	26,226,798	27,062,059
OPERATING INCOME	229,438	312,243
OTHER INCOME (EXPENSE):		
Interest and Dividend Income	298,546	297,047
Realized Gains (Losses) on Maturities of Investments	452	19,396
Miscellaneous Nonoperating Income	58	5
Interest Charges	(39)	(64)
Total Other Income (Expense)	299,017	316,384
NET INCOME	528,455	628,627
Unappropriated Retained Earnings - January 1,	14,652,489	14,436,972
Appropriation of Funds Transferred to Rate Stabilization Trust Fund	(750,000)	0
Prior Period Adjustments	852,787	(188,110)
Appropriation Returned to Town	(225,000)	(225,000)
Unappropriated Retained Earnings - December 31,	$ 15,058,731	$ 14,652,489

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
STATEMENTS OF INCOME AND APPROPRIATED RETAINED EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

RATE STABILIZATION TRUST FUND

	1999	1998
OTHER INCOME (EXPENSE):		
Interest Earned on Invested Funds	$ 619,438	$ 502,776
Accrued Interest Paid at Purchase	(19,834)	(26,169)
Gain (Loss) from Security Redemption	1,093	18,994
Purchased Power Expenses	(3,943,581)	0
NET INCOME	(3,342,884)	495,601
APPROPRIATED RETAINED EARNINGS - January 1,	9,680,755	9,185,154
ADD: Transfer from Operating Fund	750,000	0
APPROPRIATED RETAINED EARNINGS - December 31,	$ 7,087,871	$ 9,680,755

RETIREMENT TRUST FUND

	1999	1998
OTHER INCOME (EXPENSE):		
Interest Earned on Invested Funds	$ 404,289	$ 341,755
Accrued Interest Paid at Purchase	(12,642)	(15,377)
Gain (Loss) from Security Redemption	888	29,614
Annual Contribution from Light Department	133,085	96,084
Annual Pension Expense	(504,347)	(487,755)
NET INCOME (LOSS)	21,273	(35,679)
APPROPRIATED RETAINED EARNINGS - January 1,	6,324,434	6,360,113
APPROPRIATED RETAINED EARNINGS - December 31,	$ 6,345,707	$ 6,324,434

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
STATEMENTS OF CASH FLOWS
OPERATING FUND
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income	$ 528,455	$ 628,627
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	614,423	604,299
Amortization of Nuclear Fuel	25,383	21,885
Interest and Dividend Income	(298,546)	(297,047)
Realized (Gains) Losses on Sales of Investments	(452)	(19,396)
Appropriation Returned to Town	(225,000)	(225,000)
Appropriation Transferred to Rate Stabilization	(750,000)	0
Prior Period Adjustments	852,787	(188,110)
Changes in Assets and Liabilities:		
(Increase) Decrease in:		
Customer Accounts Receivable	720,709	17,049
Other Accounts Receivable	(219,434)	(16,162)
Deferred Debit-Fuel Charge	229,705	182,464
Materials and Supplies	(100,034)	21,531
Purchased Power Prepayments	22,565	1,546,329
Purchased Power Working Capital	(1,924)	(39,443)
Interest and Dividends Receivable	0	9,598
Increase (Decrease) in:		
Accounts Payable	(1,226,439)	638,626
Customer Deposits	78,595	(24,358)
Customer Deposits-Interest	18,940	18,865
Tax Collections Payable	(2,374)	(686)
Deferred Credit-Fuel Charge	332,862	0
Misc. Current and Accrued Liabilities	190,614	152,873
Net Cash Provided by Operating Activities	790,835	3,031,944
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES:		
Purchases of Utility Plant Assets	(559,374)	(398,122)
Purchases of Nuclear Fuel	(6,121)	(27,510)
Net Cash Used in Capital and Related Financing Activities	(565,495)	(425,632)

(continued - 1)

See Accompanying Notes to Financial Statements

HUDSON LIGHT AND POWER DEPARTMENT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

(concluded - 2)

	1999	1998
CASH FLOWS FROM INVESTING ACTIVITIES:		
Interest and Dividend Income	298,546	297,047
Due from Rate Stabilization Fund	(949,983)	0
Net Proceeds from Maturities (Purchases) of Investments	(1,858,793)	1,029,379
Net Cash Provided by (Used in) Investing Activities	(2,510,230)	1,326,426
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(2,284,890)	3,932,738
CASH AND CASH EQUIVALENTS - JANUARY 1	8,323,567	4,390,829
CASH AND CASH EQUIVALENTS - DECEMBER 31	$ 6,038,677	$ 8,323,567

SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:

The following amounts are considered to be cash or cash equivalents for the purpose of the statements of cash flows:

	1999	1998
Depreciation Fund	$ 126,073	$ 86,029
Depreciation Investment Fund (Note 10)	501,017	2,322,946
Operating Fund	4,975,604	5,532,756
Customer Deposits	282,344	247,137
Customer Deposits-Interest	153,139	134,199
Petty Cash	500	500
	$ 6,038,677	$ 8,323,567

Cash paid for interest expense in 1999 and 1998 was $39 and $64, respectively.

See Accompanying Notes to Financial Statements

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

The significant accounting policies of Hudson Light and Power Department are as follows:

Reporting Entity

The Hudson Light and Power Department is a component unit of the Town of Hudson, Massachusetts. The Department purchases power from various sources and sells it to the ultimate customers at rates submitted to the Massachusetts Department of Telecommunications and Energy (DTE). The Municipal Light Board (an elected Town Board) appoints a Manager who has full charge of the operations and management of the Department under the direction and control of the Municipal Light Board.

Regulation and Basis of Accounting

The Town of Hudson complies with Generally Accepted Accounting Principles (GAAP). The Town's reporting entity applies all relevant Governmental Accounting Standards Board (GASB) pronouncements. Proprietary funds and similar component units apply Financial Accounting Standards Board (FASB) pronouncements and Accounting Principles Board (APB) opinions issued on or before November 30, 1989, unless those pronouncements conflict with or contradict GASB pronouncements, in which case, GASB prevails.

Under Massachusetts law, electric rates of the Department are set by the Municipal Light Board and may be changed not more often than once every three months. Rate schedules are filed with the Massachusetts Department of Telecommunications and Energy (DTE). While the DTE exercises general supervisory authority over the Department, the Department's rates are not subject to DTE approval.

Depreciation

The general laws of Massachusetts allow utility plant to be depreciated at an annual rate of 3%. In order to change this rate, approval must be obtained from the Department of Telecommunications and Energy. Changes in annual depreciation rates may be made for financial factors relating to cash flow rather than for engineering factors relating to estimates of useful lives. The Department used a depreciation rate of 3% for 1999 and 1998.

The Department charges maintenance to expense when incurred. Replacements and betterments are charged to utility plant.

Revenues

Revenues from sales of electricity are recorded on the basis of bills rendered from monthly readings taken on a cycle basis. The revenues are based on rates established by the Department which are applied to the customers' consumption of electricity.

The Department has a power cost adjustment clause pursuant to which increased power costs (power costs in excess of amounts recovered through base rates) are billable to customers. The Department records estimated unbilled fuel adjustment charge revenue at the end of accounting periods.

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued):

Materials and Supplies
Materials and supplies are valued using the average cost method.

Taxes
The Department is exempt from federal and state income taxes. Although also exempt from property taxes the Department pays amounts in lieu of taxes to the Town of Hudson. Taxes are paid to the State of New Hampshire resulting from ownership in the Seabrook, New Hampshire Nuclear Power Plant.

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

Cash and Cash Equivalents
For purposes of the statements of cash flows, the Department considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents.

Advertising
The Department expenses advertising costs as incurred. At December 31, 1999 and 1998 advertising expense was $697 and $3,546, respectively.

Reclassification
Certain amounts in the 1998 financial statements have been reclassified to conform with the 1999 presentation with no effect on previously reported net income.

Compensated Absences
In accordance with Town and Light Department policies, employees are allowed to accumulate sick days, up to a maximum of 864 hours. Upon termination of employment with the Light Department, the employee will not be paid and upon retirement up to 50% of their accumulated sick time at employee's regular rate of pay. The percentage is based on employees age and number of years of service with the Light Department.

Employees are permitted to carry vacation time from one year to the next. Upon termination of employment with the Light Department, the employee will be paid for unused vacation time based on the employee's base rate of pay at the time of termination. Union employees have to use their vacation by April of the following year.

Allowance for Doubtful Accounts
The Light Department considers accounts receivable to be fully collectible; accordingly, no allowance for doubtful accounts is required.

NOTE 2 - UNBILLED REVENUE:

No recognition is given to the amount of sales to customers which are unbilled at the end of the accounting period.

NOTE 3 - CONCENTRATION OF CREDIT RISK:

Light Department cash is deposited with the Town Treasurer and are commingled and invested with deposits from other Town funds. Accordingly, it is not practical to disclose the related bank balance and credit risk of such cash deposits for the Light Department. Funds on deposit with financial institutions are subject to the insurance coverage limits imposed by the Federal Deposit Insurance Corporation (FDIC). The amount of insurance coverage for the Light Department deposits is not determinable because the limits of insurance are computed on a Town-wide basis.

NOTE 4 - MMWEC PARTICIPATION:

The Town of Hudson acting through its Light and Power Department is a Participant in certain Projects of the Massachusetts Municipal Wholesale Electric Company (MMWEC).

MMWEC is a public corporation and a political subdivision of the Commonwealth of Massachusetts created as a means to develop a bulk power supply for its Members and other utilities. MMWEC is authorized to construct, own or purchase ownership interests in and to issue revenue bonds to finance electric facilities (Projects). MMWEC has acquired ownership interests in electric facilities operated by other utilities and also owns and operates its own electric facilities. MMWEC sells all of the capability (Project Capability) of each of its Projects to its Members and other Utilities (Project Participants) under Power Sales Agreements (PSAs). Among other things, the PSAs require each Project Participant to pay its pro rata share of MMWEC's costs related to the Project, which costs include debt service on bonds issued by MMWEC to finance the Project, plus 10% of MMWEC's debt service to be paid into a Reserve and Contingency Fund. In addition, should any Project Participant fail to make payment, other Project Participants may be required to increase (step-up) their payments and correspondingly their Participants' share of Project Capability to an additional amount not to exceed 25% of their original Participants' share of the Project Capability. Project Participants have covenanted to fix, revise, and collect rates at least sufficient to meet their obligations under the PSAs.

MMWEC also contracts to purchase power from third parties which is resold to Members and other utilities under agreements known as Power Purchase Agreements (PPAs).

The payments required to be made to MMWEC under the PSAs and the PPAs are payable solely from Light Department revenues. Under the PSAs, each Participant is unconditionally obligated to make payments due to MMWEC whether or not the Project(s) is completed or operating and notwithstanding the suspension or interruption of the output of the Project(s).

NOTE 5 - PENSION PLAN:

The Department is a member of the Middlesex Retirement System which in turn is a member of the Massachusetts Contributory Retirement System which is governed by M.G.L. c.32 of the Massachusetts General Laws. Membership in the plan is mandatory immediately upon the commencement of employment for all permanent, full-time employees. The plan is a contributory defined benefit plan for all county employees and employees of participating towns and districts except those employees who are covered by the teachers retirement board.

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

A $30,000 salary cap, upon which members' benefits were calculated, was removed by the Middlesex Retirement System effective January 1, 1991. Members become vested after ten years of creditable service. A superannuation retirement allowance may be received upon the completion of twenty years of service or upon reaching the age of 55 with ten years of service. Normal retirement for most employees occurs at age 65 (for certain hazardous duty and public safety positions normal retirement is at age 55).

A retirement allowance consists of two parts: an annuity and a pension. A member's accumulated total contributions and a portion of the interest they generate constitute the annuity. The differential between the total retirement benefit and the annuity is the pension. The average retirement benefit is approximately 80-85% pension and 15-20% annuity.

Active members contribute either 5, 7, 8, or 9% of their gross regular compensation. The percentage rate is keyed to the date upon which an employee's membership commences. Members hired after 1978 contribute an additional 2% of annual pay above $30,000. These contributions are deposited in the Annuity Savings Fund and earn interest at a rate determined by the Public Employees' Retirement Administration's (PERA's) actuary. When a member's retirement becomes effective, his/her deductions and related interest are transferred to the Annuity Reserve Fund. Any cost-of-living adjustment granted since 1981 and any increase in other benefits imposed by state law after that year is borne by the state.

Members who become permanently and totally disabled for further duty may be eligible to receive a disability retirement allowance. The amount of benefits to be received in such cases is dependent upon several factors, including: whether or not the disability is work related, the member's age, years of creditable service, level of compensation, veterans' status, and group classification. Employees who resign from service and who are not eligible to receive a retirement allowance or are under the age of 55 are entitled to request a refund of their accumulated total contributions. In addition, depending upon the number of years of creditable service, such employees are entitled to receive either zero (0%) percent, fifty (50%) percent, or one hundred (100%) percent of the regular interest which has accrued upon those contributions.

NOTE 5 - PENSION PLAN (continued):

Survivor benefits are extended to eligible beneficiaries of members whose death occurs prior to or following retirement.

The pension portion of any retirement benefit is paid from the Pension Fund of the System. The Governmental unit employing the member must annually appropriate and contribute the amount of current year pension payments as determined by PERA's actuary. The Town of Hudson's last available actuarial study was on January 1, 1997. As of that date, the Town's share of the total estimated actuarial liability of the system was $21,400,291 and its share of assets was $11,332,679, leaving an estimated unfunded actuarial liability of $10,067,612. Because the Department's employees comprise only approximately 25% of the Town of Hudson's participants in the retirement system, the Department's portion of the unfunded actuarial accrued liability is not separately calculated by PERA's actuary.

The Department's payments to the Town of Hudson for pension costs are determined on a pay-as-you-go method. However, the Hudson Light and Power Department has established the Employee's Retirement Trust Fund as a source of funds to reimburse the town for its share of pension costs and to provide for the Department's unfunded actuarial liability. (See Footnote 16)

NOTE 6 - ESCROW RESERVE MAINE YANKEE:

The Department had established an Escrow Cash Account in 1998 to set aside monies to pay Maine Yankee subject to the outcome of pending litigation. In 1999, Maine Yankee was settled and paid off.

NOTE 7 - DEPRECIATION FUND:

Pursuant to provisions of the Commonwealth General Laws, cash in an amount equivalent to the annual depreciation expense is transferred from unrestricted funds to the depreciation fund. Interest earned on the balance of the fund must also remain in the fund. Such cash may only be used to pay for additions to utility plant and for various contractual commitments relating to power supply expenditures.

NOTE 8 - OTHER RECEIVABLES:

Other receivables represent funds due to the Department as follows:

	1999	1998
Merchandising and Jobbing	$ 16,652	$ 28,584
Oil Spill Reimbursement	0	182,915
Power Contract Refunds	414,281	0
	$ 430,933	$ 211,499

NOTE 9 - PURCHASED POWER WORKING CAPITAL:

MMWEC Participants approved working capital amendments to the various power purchase agreements. The implementation of the Working Capital Program began August 1, 1985. The income earned allocated to the Department will be applied as a credit to MMWEC Power Sales Billing. The balance in the Fund as of December 31, 1999 and 1998 is $340,076 and $338,152, respectively.

NOTE 10 - INVESTMENT:

The Department owns shares of Hydro Quebec Phase II stock. The securities are stated at cost. Fair market value approximates stated value.

NOTE 11 - INVESTMENTS AND CASH EQUIVALENTS:

The Department's cash, cash equivalents and investments are held by the Hudson Town Treasurer. The Department's investments are classified as held to maturity and are recorded at unamortized cost plus accrued interest paid at purchase. The Depreciation Investment Fund and the Insurance Escrow Fund are allocated between investments and cash equivalents as follows:

	Investments	Cash Equivalents	Total
		1999	
Depreciation Investment Fund	$ 3,191,504	$ 501,017	$ 3,692,521
		1998	
Depreciation Investment Fund	$ 1,322,263	$ 2,322,946	$ 3,645,209

The gross unrealized holding gains on the U.S. Treasury Notes were $8,704 and the gross unrealized holding gains on the Certificates of Deposits were $901, at December 31, 1999.

At December 31, 1999 total investments are comprised of the following securities maturing within one year.

	Cost	Fair Value
Certificates of Deposit	$ 3,191,504	$ 3,190,652

NOTE 12 - PRIOR PERIOD ADJUSTMENTS:

During 1999 and 1998, the Department received and paid certain amounts relating to activities that occurred in prior years as follows:

		1999	1998
Boston Edison	- True-Up for 1995 and 1996	$ 24,016	$ 54,829
ISO New England	- 1997 Tariff Billings Settlement	0	(242,939)
Deferred Fuel Charge Adjustment		179,743	0
NEPool	- 97-98 Overcharge Settlement	250,602	0
NE Power	- 96-98 Tariff #9 Settlement	398,426	0
		$ 852,787	$ (188,110)

NOTE 13 - APPROPRIATION RETURNED TO TOWN:

By vote of the Municipal Light Board, the Department agreed to contribute $225,000 in 1999 and 1998 to the Town of Hudson in lieu of real estate taxes. All contributions to the Town are voluntary.

NOTE 14 - MAJOR CUSTOMER:

The Department's revenues include approximately $8,696,920 and $9,396,025 billed to one major customer during 1999 and 1998, respectively. Amounts due from this customer included in accounts receivable were $0 and $678,946 at December 31, 1999 and 1998, respectively.

NOTE 15 - RATE STABILIZATION TRUST FUND:

The Hudson Light and Power Board of Commissioners voted (January 11, 1997) to establish a Rate Stabilization Trust Fund for the purpose of providing the necessary funds to meet future power supply costs. Approximately $9 million was transferred from the special insurance escrow reserve account to the Rate Stabilization Trust Fund in March, 1997. Under the terms of the trust any assets remaining after the final payment of Power Sales Agreement obligations will revert back to the Department.

The Department's cash equivalents and investments are held by the Hudson Town Treasurer. The Department's investments are classified as held to maturity and are recorded at unamortized cost plus accrued interest paid at purchase.

NOTE 15 - RATE STABILIZATION TRUST FUND (continued):

At December 31, 1999 total cash equivalents and investments are comprised of the following securities maturing within one year.

	Cost Plus Accrued Interest	Accrued Interest	Unamortized Cost	Fair Value
Cash Equivalents	$ 1,086,357	$ 0	$ 1,086,357	$ 1,083,931
U.S. Treasury Notes	6,277,809	367	6,277,442	6,135,133
Certificates of Deposit	673,688	4,713	668,975	670,000
	$ 8,037,854	$ 5,080	$ 8,032,774	$ 7,889,064

The gross unrealized holding gains on the U.S. Treasury Notes were $0, the gross unrealized holding losses were $142,676, the gross unrealized holding gains on cash equivalents were $298, and the gross unrealized holding losses were $2,724, at December 31, 1999. The gross unrealized holding gains on Certificates of Deposit were $446 and the gross unrealized holding losses were $4,134.

NOTE 16 - RETIREMENT TRUST FUND:

The Department has made provisions for their share of the Town of Hudson's unfunded actuarial liability by setting up the Town of Hudson Light and Power Department Employees' Retirement Trust to which they make contributions as deemed necessary by an actuary hired every two years to analyze the trust's estimated actuarial liability and assets. The last available actuarial study of the Department's trust indicated that the trust was underfunded. The Department has adjusted their current contribution percentage to provide for the underfunding.

The Department's cash equivalents and investments are held by the Hudson Town Treasurer. The Department's investments are classified as held to maturity and are recorded at unamortized cost plus accrued interest paid at purchase.

At December 31, 1999 total cash equivalents and investments are comprised of the following securities maturing within one year.

	Cost Plus Accrued Interest	Accrued Interest	Unamortized Cost	Fair Value
Cash Equivalents	$ 743,694	$ 0	$ 743,694	$ 743,795
U.S. Treasury Notes	4,842,338	6,597	4,835,741	4,676,366
Certificates of Deposit	759,675	0	759,675	760,000
	$ 6,345,707	$ 6,597	$ 6,339,110	$ 6,180,161

NOTE 16 - RETIREMENT TRUST FUND (continued):

The gross unrealized holding gains on the U.S. Treasury Notes were $17,442, the gross unrealized holding losses were $183,414, the gross unrealized holding gains on Certificate of Deposits were $325, and the gross unrealized holding gains on Cash Equivalents were $101, at December 31, 1999.

NOTE 17 - COMMITMENTS AND CONTINGENCIES:

Stow Municipal Electric Department

The Hudson Light and Power Department currently services the Towns of Hudson and Stow Massachusetts.

The Town of Stow voted to withdraw from the Hudson Light and Power Department and, in accordance with the provisions of the General Laws, Hudson Light and Power Department has sought to recover from Stow the value of its property rights and the cost of severance or stranded investment, resulting from Stow's action. As of the end 1995 this matter was pending before the Department of Telecommunications and Energy and it was counsel's opinion that the DTE would enter a finding in favor of Hudson's claim that stranded investment, which results from Stow's withdrawal, must be included in the damages to be paid by Stow.

The management of the Hudson Light and Power Department has vigorously pursued its claim for damages. On February 16, 1996, the DTE awarded damages in the amount of $2,554,472. The Department's estimate of damages is significantly higher than this amount and the Department filed a notice of appeal to the Supreme Judicial Court, in accordance with the provisions of G.L. c.164, 25.

After argument before the Supreme Court, the Court entered an order remanding the matter of stranded costs to the Department of Telecommunications and Energy to be determined "in accordance with the public interest in fair competition, equal treatment, low rates, and other factors relevant to the department's [of Telecommunications and Energy] duty to protect ratepayers." The Court directed the DTE to meet its "obligation to protect the interests of all ratepayers, not just departing customers." It is counsel's opinion that the DTE, in reconsidering the questions presented by Stow's withdrawal, will have to reevaluate those costs in accordance with the Court's direction.

MMWEC Contingencies and Litigation

Through its participation in MMWEC, the Hudson Light and Power Department is contingently liable on the various Projects in which they participate as detailed below.

MMWEC operates the Stony Brook Intermediate Project and the Stony Brook Peaking Project fossil-fueled power plants. MMWEC has a 22.7 MW interest in the W.F. Wyman Unit No. 4 plant, currently operated by a subsidiary of Florida Power & Light pursuant to an April 1999 agreement. Central Maine Power Company's sale of its power plants to Florida Power & Light included CMP's 59% share of W.F. Wyman Unit No. 4 for which it was the lead owner.

NOTE 17 - COMMITMENTS AND CONTINGENCIES (continued):

MMWEC's 11.6% ownership interest in the Seabrook Station nuclear generating unit represents a substantial portion of its plant investment and financing program. In addition, MMWEC has a 4.8% ownership interest in the Millstone Unit 3 nuclear unit.

The MMWEC Seabrook and Millstone Project Participants, per the PSAs, are liable for their proportionate share of the costs of a nuclear incident at those power plants as outlined in the Price-Andersen Act. The Project Participants are also liable for the decommissioning expenses, which are being funded through monthly Project billings.

In November 1997, the Commonwealth of Massachusetts enacted legislation effective March 1, 1998 to restructure the electric utility industry. MMWEC and the municipal light departments are not specifically subjected to the legislation. However, it is management's belief that industry restructuring and retail customer choice promulgated within the legislation will have an effect on MMWEC and the Participant's operations.

MMWEC is involved in various legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position of the company.

As of December 31, 1999 total capital expenditures associated with the Projects amounted to $1,482,654,000, of which $162,203,000 represents the amount associated with the Department's Project Capability. MMWEC's debt outstanding for the Projects included Power Supply System Revenue Bonds totaling $1,214,850,000, of which $125,180,000 is associated with the Department's share of Project Capability. As of December 31, 1999, MMWEC's total future debt service requirement on outstanding bonds issued for Projects is $1,839,166,000, of which $202,844,000 is anticipated to be billed to the Department.

Hudson Light and Power Department has entered into PSAs and PPAs with MMWEC. Under these agreements, the Department is required to make certain payments to MMWEC. The aggregate amount of Hudson Light and Power Department's required payments under the PSAs and PPAs, exclusive of the Reserve and Contingency Fund billings, through MMWEC at December 31, 1999 and estimated for future years is shown below.

		ANNUAL COST
For years ended December 31,	1999	$ 11,348,000
	2000	11,350,000
	2001	11,351,000
	2002	11,378,000
	2003	11,402,000
	Later Fiscal Years	146,015,000
	TOTAL	$ 202,844,000

In addition, the Department is required to pay its share of the Operation and Maintenance (O&M) costs of the Projects in which they participate. The Department's total O&M costs including debt service under the PSAs were $16,863,000 and $16,994,000 for the years ended December 31, 1999 and 1998, respectively.

HUDSON LIGHT AND POWER DEPARTMENT
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 1999 AND 1998
(000)

	PERCENTAGE SHARE	TOTAL PROJECT EXPENDITURES TO DATE	PARTICIPANTS SHARE	DEBT ISSUED & OUTSTANDING 12/31/99	PARTICIPANTS SHARE	TOTAL DEBT SERVICE ON BONDS OUTSTANDING	PARTICIPANTS SHARE
Stony Brook Peaking Project	-	$ 56,534	$ -	$ 26,740	$ -	$ 29,737	$ -
Stony Brook Intermediate Project	-	151,421	-	89,765	-	107,580	-
Nuclear Mix No. 1-SBK	3.3984	14,987	509	13,847	471	19,037	647
Nuclear Mix No. 1-MLS	3.3984	110,879	3,768	102,443	3,481	140,842	4,786
Nuclear Project No. 3-MLS	1.5997	136,955	2,191	191,565	3,064	291,216	4,659
Nuclear Project No. 4-SBK	4.2300	312,614	13,224	219,180	9,271	340,531	14,404
Nuclear Project No. 5-SBK	1.8613	85,439	1,590	66,560	1,239	105,234	1,959
Wyman Project	9.2536	7,518	696	4,190	388	5,098	472
Project No. 6-SBK	23.1278	606,307	140,225	463,795	107,266	760,628	175,917
TOTAL		$ 1,482,654	$ 162,203	$ 1,178,085	$ 125,180	$ 1,799,903	$ 202,844
Commercial Paper Program	-	$ -	$ -	$ 36,765	$ -	$ 39,263	$ -

	PERCENTAGE SHARE	OPERATION & MAINTENANCE 12/31/98	PARTICIPANTS SHARE	OPERATION & MAINTENANCE 12/31/99	PARTICIPANTS SHARE
Stony Brook Peaking Project	-	$ 8,783	$ -	$ 8,902	$ -
Stony Brook Intermediate Project	-	38,073	-	41,367	-
Nuclear Mix No. 1-SBK	3.3984	1,975	67	1,940	66
Nuclear Mix No. 1-MLS	3.3984	17,943	610	16,666	566
Nuclear Project No. 3-MLS	1.5997	28,313	453	27,806	445
Nuclear Project No. 4-SBK	4.2300	33,295	1,408	31,489	1,332
Nuclear Project No. 5-SBK	1.8613	9,651	180	9,073	169
Wyman Project	9.2536	2,155	199	2,855	264
Project No. 6-SBK	23.1278	60,866	14,077	60,622	14,021
TOTAL		$ 201,054	$ 16,994	$ 200,720	$ 16,863
Commercial Paper Program	-	$ -	$ -	$ -	$ -

See Independent Auditors' Report

HUDSON LIGHT AND POWER DEPARTMENT
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 1999 AND 1998
(000)

	PERCENTAGE SHARE	2000 ANNUAL COST	PARTICIPANTS SHARE	2001 ANNUAL COST	PARTICIPANTS SHARE	2002 ANNUAL COST	PARTICIPANTS SHARE
Stony Brook Peaking Project	-	$ 5,199	$ -	$ 5,200	$ -	$ 5,156	$ -
Stony Brook Intermediate Project	-	12,938	-	12,938	-	12,938	-
Nuclear Mix No. 1-SBK	3.3984	1,369	47	1,369	47	1,369	47
Nuclear Mix No. 1-MLS	3.3984	10,125	344	10,124	344	10,125	344
Nuclear Project No. 3-MLS	1.5997	16,903	270	16,910	271	16,909	270
Nuclear Project No. 4-SBK	4.2300	18,809	796	18,805	795	18,808	796
Nuclear Project No. 5-SBK	1.8613	5,800	108	5,929	110	5,929	110
Wyman Project	9.2536	566	52	565	52	564	52
Project No. 6-SBK	23.1278	42,074	9,731	42,076	9,731	42,078	9,732
TOTAL		$ 113,783	$ 11,348	$ 113,916	$ 11,350	$ 113,876	$ 11,351
Commercial Paper Program	-	$ 8,879	$ -	$ 8,951	$ -	$ 8,905	$ -

	PERCENTAGE SHARE	2003 ANNUAL COST	PARTICIPANTS SHARE	2004 ANNUAL COST	PARTICIPANTS SHARE	AFTER 2004 ANNUAL COST	PARTICIPANTS SHARE
Stony Brook Peaking Project	-	$ 5,178	$ -	$ 5,180	$ -	$ 3,824	$ -
Stony Brook Intermediate Project	-	12,937	-	12,938	-	42,891	-
Nuclear Mix No. 1-SBK	3.3984	1,369	47	1,365	46	12,197	413
Nuclear Mix No. 1-MLS	3.3984	10,127	344	10,100	343	90,240	3,067
Nuclear Project No. 3-MLS	1.5997	16,952	271	17,013	272	206,529	3,305
Nuclear Project No. 4-SBK	4.2300	19,395	820	19,958	844	244,756	10,353
Nuclear Project No. 5-SBK	1.8613	6,023	112	6,127	114	75,426	1,405
Wyman Project	9.2536	567	52	570	53	2,266	211
Project No. 6-SBK	23.1278	42,078	9,732	42,071	9,730	550,251	127,261
TOTAL		$ 114,626	$ 11,378	$ 115,322	$ 11,402	$ 1,228,380	$ 146,015
Commercial Paper Program	-	$ 8,733	$ -	$ 3,628	$ -	$ 167	$ -

See Independent Auditors' Report

Goulet, Salvidio & Associates, P.C.

Certified Public Accountants

James F. Goulet, CPA, MST
Catherine A. Kuzmeskus, CPA

Michael A. Salvidio, CPA
James R. Dube, CPA

INDEPENDENT AUDITORS' REPORT ON SUPPLEMENTAL INFORMATION

The Municipal Light Board
Hudson Light and Power Department

Our audits were made for the purpose of forming an opinion on the financial statements of Hudson Light and Power Department for the years ended December 31, 1999 and 1998, which are presented in the preceding section of this report. The supplemental information presented on pages 22 through 24 is for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the 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.

Goulet, Salvidio & Associates, P.C.

Goulet, Salvidio + Associates, P.C.

Worcester, Massachusetts
May 14, 2000

Nine Irving Street · Worcester, MA 01609 · Tel: 508-757-5957 · Fax: 508-753-0948 · E-mail: gsamycpa@aol.com

HUDSON LIGHT AND POWER DEPARTMENT
SCHEDULES OF OPERATING REVENUES
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

	1999	1998
Sales to Residential Customers	$ 6,822,138	$ 6,519,798
Sales to Commercial Customers	1,633,422	1,583,286
Sales to Power Customers	12,054,405	12,593,499
Private Property Lighting Sales	83,905	80,220
Municipal Sales		
Hudson Street Lights	103,097	94,160
Hudson Municipal Buildings	66,448	67,256
Hudson Municipal Power	353,311	346,460
All Electric Municipal Buildings	403,450	393,294
Stow and Berlin Street Lights	6,869	5,238
Stow, Maynard and Other Municipal Services	114,325	116,763
Total Revenue from Sales of Electricity	21,641,370	21,799,974
Power Adjustment Charges		
Residential Sales	913,453	871,350
Commercial Sales	324,584	314,465
Power Sales	4,069,506	4,324,274
Private Property Lighting	13,224	12,795
Municipal Power Adjustment Charges		
Street Lighting Stow, et al	906	775
Municipal Power Hudson	94,873	93,632
Municipal Commercial Hudson	13,366	13,562
Municipal Power Stow, et al	24,572	26,413
Municipal Commercial Stow, et al	2,928	2,669
Municipal All Electric	63,016	61,517
Miscellaneous Electric Sales	(742,308)	(182,464)
Total Power Adjustment Charges	4,778,120	5,538,988
Other Income		
Other Electric Revenues	36,746	35,340
TOTAL OPERATING REVENUES	$ 26,456,236	$ 27,374,302

See Independent Auditors' Report on Supplemental Information

HUDSON LIGHT AND POWER DEPARTMENT
SCHEDULES OF OPERATION AND MAINTENANCE EXPENSES
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

	1999	1998
PRODUCTION EXPENSES:		
Nuclear Power Generation:		
Operation Supervision	$ 18,144	$ 19,011
Fuel	32,193	28,468
Coolants and Water	1,687	1,556
Steam Expenses	13,152	9,583
Electric Expenses	3,497	3,201
Miscellaneous Nuclear Power Generation Expenses	36,624	29,008
Maintenance Supervision	8,506	7,813
Maintenance of Structures	2,575	6,111
Maintenance of Reactor Plant Equipment	16,371	7,508
Maintenance of Generation and Electric Plant	12,901	8,449
Maintenance of Miscellaneous Nuclear Power	386	457
Total Nuclear Power Generation Expenses	146,036	121,165
Other Power Generation:		
Operation Supervision	29,030	29,376
Fuel-Oil	52,181	52,699
Fuel-Natural Gas	98,958	76,183
Generation Expenses	64,195	68,607
Generation Expenses-Lube	8,934	10,803
Miscellaneous Other Power Generation Expenses	104,307	72,684
Maintenance Supervision	27,887	27,963
Maintenance of Structures	98,252	78,892
Maintenance of Generation and Electric Plant	122,567	82,857
Maintenance of Miscellaneous Generation Plant	77	93
Total Other Power Generation Expenses	606,388	500,157
TOTAL PRODUCTION EXPENSES	$ 752,424	$ 621,322
PURCHASED POWER EXPENSES:		
Purchased Power-Entitlement	$ 19,929,177	$ 20,473,013
Purchased Power-Nepex System Control and Load	1,072,762	1,504,143
Dispersion	9,193	13,843
Other Purchased Power Expenses	(4,140)	19,630
TOTAL PURCHASED POWER EXPENSES	$ 21,006,992	$ 22,010,629

See Independent Auditors' Report on Supplemental Information

HUDSON LIGHT AND POWER DEPARTMENT
SCHEDULES OF OPERATION AND MAINTENANCE EXPENSES
FOR THE YEARS ENDED DECEMBER 31, 1999 and 1998

	1999	1998
TRANSMISSION EXPENSES	$ 1,502,955	$ 1,743,718
DISTRIBUTION EXPENSES:		
Operation Supervision and Engineering	$ 32,027	$ 30,973
Station Expenses	125,376	120,013
Overhead Line Expenses	9,420	7,237
Underground Line Expenses	3,006	83
Street Lighting and Signal Expenses	9,825	7,747
Meter Expenses	70,113	79,162
Customer Installation Expenses	5,335	3,880
Miscellaneous Distribution Expenses	8,226	11,116
Maintenance Supervision and Engineering	32,055	31,129
Maintenance of Station Equipment	332	431
Maintenance of Overhead Lines	275,098	230,346
Maintenance of Underground Lines	29,041	43,029
Maintenance of Line Transformer	7,186	27,007
Maintenance of Street Lighting	7,699	10,241
Maintenance of Meters	1,693	1,105
TOTAL DISTRIBUTION EXPENSES	$ 616,432	$ 603,499
GENERAL EXPENSES:		
Supervision	$ 14,747	$ 13,433
Meter Reader Expenses	55,160	52,678
Customer Records and Collection Expenses	247,378	240,932
Miscellaneous Sales Expenses	8,462	8,363
Administrative and General Salaries	345,836	332,077
Office Supplies and Expenses	18,084	19,100
Outside Services Employed	118,789	133,138
Property Insurance	24,446	66,601
Injuries and Damages	62,767	20,429
Employee Pension and Benefits	650,918	426,257
Regulatory Commission Expenses	4	1
General Advertising Expense	3,503	3,068
Miscellaneous General Expenses	41,513	45,494
Maintenance of General Plant	54,461	55,133
Transportation Expenses	63,894	36,757
TOTAL GENERAL EXPENSES	$ 1,709,962	$ 1,453,461
REAL ESTATE AND OTHER TAXES	$ 23,610	$ 25,131

See Independent Auditors' Report on Supplemental Information