Eastern Utilities Associates Annual Report 1984

EUA System Companies – The Communities We Serve

To Our Shareholders:

I am pleased to report that 1984 was another successful year for Eastern Utilities Associates. Year-end statistics reflect the continuation of financial growth which shows no signs of abating. Once again we finished the year with more kilowatthour sales of electricity, with increased consolidated net income, and with greater earnings per share. As a result, for the third consecutive year your quarterly dividend was increased, this time from 45.5¢ per share to 48.5¢ per share. I am confident that we can look forward to further improvement in 1985.

A healthier national and regional economy has stimulated an increase in the use of electricity in our service area, the rate of unemployment for both Massachusetts and Rhode Island is significantly less than the national average. The rise in kilowatthour sales volume, together with higher electric rates in effect during 1984, resulted in increased earnings. Consolidated net income jumped 18.5% to a record $30.1 million from 1983's $25.4 million. Earnings per average common share increased to $2.85, despite an additional 1.5 million average common shares outstanding.

"Consolidated net income jumped 18.5% to a record $30.1 million from 1983's $25.4 million. Earnings per average common share increased to $2.85, despite an additional 1.5 million average common shares outstanding."

Our successful performance drew favorable attention from investors. The average monthly volume of EUA shares traded increased substantially from 214,000 shares in 1983 to 365,000 shares in 1984.

EUA shares ended 1984 at $18. That price was two percent above book value and marked the first time in eight years that the year-end closing market price exceeded book value.

Last year also marked the third consecutive year-end that the EUA System had no short-term bank debt, while the earned return on common equity rose for the fifth consecutive year, from 16.2% in 1983 to 16.5% in 1984.

Along with EUA's market performance came improved credit quality ratings. Standard & Poor's Corporation raised its ratings on the debt securities of EUA's subsidiaries, Eastern Edison Company and Blackstone Valley Electric Company, from BBB to BBB+. While I am pleased with this improvement, I believe it continues to be in the best interest of EUA's shareholders and customers to maintain credit quality ratings in the A+/AA range. We will continue our efforts to reach that level.

In December 1983 our wholesale generation and transmission company, Montaup Electric Company, received permission from the Federal Energy Regulatory Commission (FERC) to implement a $15 million rate increase. This increase remained in effect throughout 1984 and had a major impact on our earnings. FERC, which regulates approximately 78% of System revenues, permits utilities to use for rate-setting purposes a forward-looking test year, allows up to 50% of a utility's construction work in progress to be included in rate base, and traditionally has permitted recovery of investments in cancelled construction projects.

Increased kilowatthour sales and a slowing of escalating costs enabled us to defer seeking rate increases for the System's two retail operating subsidiaries.

Improved cash flow last year, together with lower financing requirements, enabled EUA to reduce its level of external financing to $55.9 million, just about half the amount required in 1983. At present we do not feel it will be necessary to raise any permanent capital in 1985 and we do not anticipate the need to issue additional common shares for the foreseeable future, except through the dividend reinvestment plan.

"At present we do not feel it will be necessary to raise any permanent capital in 1985, and we do not anticipate the need to issue additional common shares for the foreseeable future..."

EUA's support of nuclear power spans almost three decades. Energy produced by the System's interests in five of the nuclear generating units now on-line in New England has served our customers well.

We remain committed to using economical and reliable sources of nuclear power to fill base load capacity needs and further displace high-cost oil. Construction costs associated with Millstone No. 3 and Seabrook No. 1 nuclear units are being closely monitored. Economic analysis of these two projects continues to show long-term benefits to our rate-payers.

Commercial operation for Millstone No. 3, a unit now 93% complete, is scheduled for May 1986. Through Montaup, we have a 4% ownership in this unit.

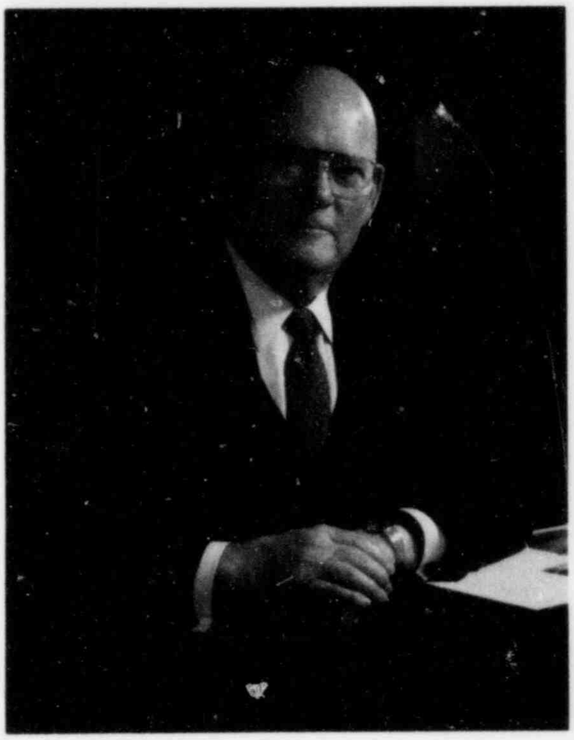
Seabrook No. 1 unit, now 83% complete, is targeted for operation in late 1986. Montaup owns 2.9% of this unit. A series of unsettling events in 1984 prompted the joint owners to change the administration of the unit's construction and ultimate operation. Responsibility has been transferred from the lead participant, Public Service Company of New Hampshire, to a new corporate entity, New Hampshire Yankee Corporation, which is being given direction by a seven-member Executive Committee representing the sixteen joint owners. I have been Chairman of the Executive Committee since January 1, 1985. Our immediate task is to monitor the expenditure of funds and to assure that the quality of construction meets all regulatory requirements. Beyond that, our purpose is to bring the project to a safe and cost-effective completion as soon as possible.

I am optimistic that 1985 will see a further improvement in the economic climate within our region. The Trustees and management of your Association look to the future with confidence. We intend to continue to meet the needs of both our customers and shareholders.

Very truly yours,

John F. G. Eichorn

John F. G. Eichorn, Jr.
President



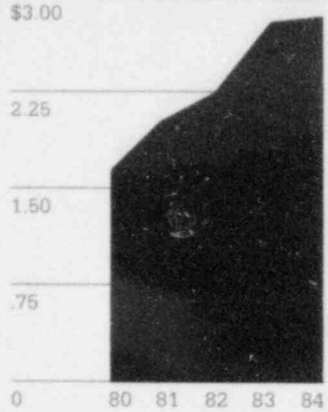
Review of Operations

E*arnings Increase; Dividend Raised; Market Price Improves* – Consolidated Net Income for 1984 increased by $4.7 million to $30.1 million. This was an increase of 18.5% over 1983's $25.4 million. The improvement in Consolidated Net Income enabled the System's earned return on average common equity to increase to 16.5%. Even though there were approximately 1.5 million or 17% additional average common shares outstanding, the growth in earnings per average common share was 1.8%. Earnings per average common share were $2.85, $0.05 over 1983.

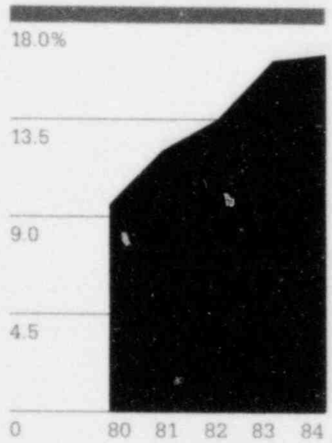
Consolidated Net Income increased to $30.1 million. Dividend payments increased for third consecutive year.

The continued improvement in Consolidated Net Income can be attributed to the carryover effect of rate relief granted in late 1983 and, to a lesser extent, to a 2.4% increase in total kilowatthour (kwh) sales resulting from a strong economy within our service territory.

Once again we were able to meet our stated goal of providing dividend increases at regular intervals. The quarterly dividend rate was increased from 45.5¢ per share to 48.5¢ per share, effective with the May 1984 dividend. This was the third consecutive year in which our dividend was increased.



Earnings and Dividends:
■ Earnings
■ Dividends
Earnings have continuously improved since 1980 and achieved a high in 1984. Dividends were increased for the third consecutive year.



Return on Average Common Equity: Our continuously improving return on common equity is a reflection of the continued strengthening of our financial position.

Investor confidence in the overall improvement in the System's financial viability also resulted in improvement in the market value of EUA common shares. Average monthly trading volume increased substantially in 1984. The closing market price of $18 at year-end was 102% of book value. This marks the first time in eight years that the market value of EUA common shares exceeded their book value at year-end.

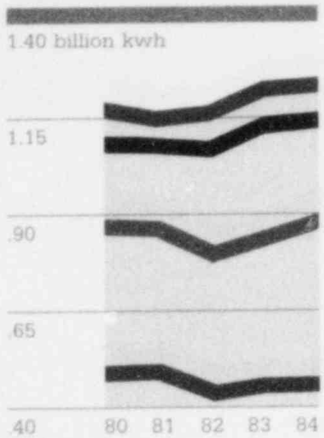
A detailed discussion of kwh sales growth and rate case activity is provided later in this report. In addition, a comparison of Operating Revenues, kwh Sales and Expenses is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations" on page 20.

R*etail Sales Increase* – Retail sales of electricity rose 1.9% from 3.1 to 3.2 billion kilowatthours in 1984. Improved national and local business conditions combined to boost industrial sales by 5.7%.

Weather conditions play an important role in determining the amount of residential and commercial kilowatthour sales each year. Warmer-than-normal winter temperature patterns, particularly during the last quarter, tempered our customers' use of electricity for central heating and auxiliary electric-heating devices. Also, summer temperatures were significantly cooler than those of the prior year, which reduced the demand for air-conditioning. However, strong economic activity in the System's service territories more than offset the impact of these abnormal weather variables and, as a result, sales to residential and commercial customers, which account for 73% of total retail sales, rose about 1%.

Increased Sales Delays Need For Retail Rate Relief – The trend of rapidly escalating costs of providing electric service abated during 1984, reflecting lower inflation, relatively stable fuel prices, a period of higher employment and increased electricity sales. These factors made it unnecessary for the System to seek rate relief in base rates in 1984, for Blackstone Valley Electric Company and Eastern Edison Company, the System's two retail subsidiary companies.

Improved economic conditions, increased electricity sales delays need for retail rate relief.



Primary Sales by Customer Class:
- **Residential**
- **Commercial**
- **Industrial**
- **Other**

Increased kilowatthour sales in 1984 reflected a continuation of the strong economic growth in our service territories.

Responsive Federal Wholesale Regulation Plays Important Role; FERC Rate Request Approved – Responsive regulation by the Federal Energy Regulatory Commission (FERC) relative to the System's wholesale electric business continues to contribute to our financial health. FERC regulates approximately 78% of System revenues and generally pursues a progressive philosophy in rate making. FERC uses a forward-looking test year, allows a portion of construction work in progress (CWIP) in rate base and has historically permitted the recovery of investments associated with the abandonment of construction projects.

In December 1983 FERC allowed Montaup Electric Company to implement a $15 million rate increase which included approximately $103 million of CWIP in rate base.

In December 1984, FERC issued an order allowing Montaup to implement a $17.6 million rate increase beginning in June 1985. In this request about $170 million of CWIP was included in rate base. The order was in response to Montaup's November 1984 rate filing.

Table of Recent Rate Relief Granted

Jurdisdiction	Annual Revenue (000's) Requested	Granted	Effective Date	Return on Equity
Federal (FERC)	$18,100	$16,800*	1/09/83	18.00%
Federal (FERC)	17,400	15,000*	12/28/83	16.20%
Federal (FERC)	17,600	17,600*	6/05/85	16.75%
Rhode Island	5,900	1,800	11/10/83	15.20%
Massachusetts	6,200	100	1/31/84	15.25%

* Granted on a subject to refund basis

Responsive Federal Energy Regulatory Commission regulation continues to contribute to System's financial health.

Credit Ratings Raised; 1985 External Financing Requirements Minimal – In December 1984, Standard & Poor's Corporation, in recognition of the continued strengthening of our financial position, raised its credit quality ratings on the debt securities of Eastern Edison and Blackstone from BBB to BBB+. We are pleased with this improved rating, but continue our efforts to obtain credit quality ratings in the A+/AA range.

The combination of a 50% increase in internal cash generation; utilization of the remaining $19 million in proceeds from a tax-exempt financing completed in 1983; and lower cash construction requirements enabled the System to reduce the level of external financing in 1984 to $55.9 million. This amount was about half the amount required in 1983.

The continuation of a high level of shareholder participation in our Dividend Reinvestment and Common Share Purchase Plan provided $7.8 million of additional common equity in 1984. In addition, $1.6 million of common equity was obtained from our Employees' Savings and Employees' Share Ownership Plans.

Eastern Edison completed a private placement of $40 million of first mortgage bonds in September. The new bonds had a 13.9% interest rate for the $21 million which mature in 1987. The remaining $19 million mature in 1988 and have an interest rate of 14.2%.

The completion of this bond financing enabled Eastern Edison to repay a $10 million bank term-loan and retire $25.8 million of first mortgage bonds that were close to their mandatory retirement date. The remaining proceeds were temporarily invested by Eastern Edison and had been partially utilized by year-end.

Blackstone successfully completed a $6.5 million low-cost, tax-exempt bond issue in December 1984. Blackstone's issue has a 30-year maturity with a floating interest rate that is adjusted each week. A January 1985

Credit ratings raised. System again ends year with no short-term debt.

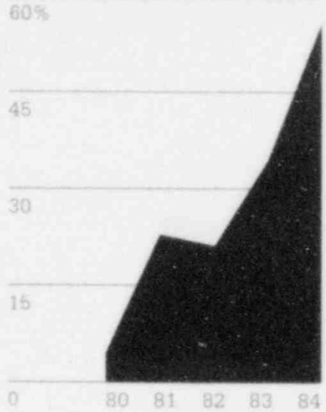
interest rate on this issue was just over 5%. This financing was undertaken to finance the rehabilitation of Blackstone's 88-year-old hydroelectric generating plant in Pawtucket, Rhode Island.

Completion of the above financings has enabled the System to end the year with no short-term debt for the third consecutive year.

Substantially lower cash construction requirements in 1985, together with a further increase in internal cash generation, should enable the System to avoid having to raise any permanent capital in 1985.

It is anticipated that our Dividend Reinvestment and Common Share Purchase, Employees' Savings and Employees' Share Ownership Plans will provide approximately $10 million. Any additional external funds which may be required in 1985 will come from short-term bank loans.

Construction Expenditures Declining – The System's 1984 construction expenditures were $95.2 million, down from $103.3 million in 1983. Generation-related projects amounted to $78.2 million, with $20.2 million and $31.6 million, respectively, spent on EUA's portion of the Seabrook and Millstone nuclear units through Montaup Electric Company, the System's generation and transmission subsidiary. In addition, $19.7 million was expended to complete the conversion of Montaup's Somerset Station from oil to coal, while $6.7 million was spent on other generation related projects. Expenditures for transmission and distribution system upgrading and for general plant improvements amounted to $17.0 million.



Internally Generated Funds: The dramatic improvement in internally generated funds continued during 1984. By 1986, we expect to meet all of our cash construction requirements with internally generated funds.

Construction requirements for the five-year period 1985-1989, are currently projected at $185.0 million including the current estimate of $82 million for 1985. The planned completion of the Millstone and Seabrook No. 1 nuclear units in 1986 will mean a substantial reduction in construction expenditures for the balance of the five-year period ending in 1989.

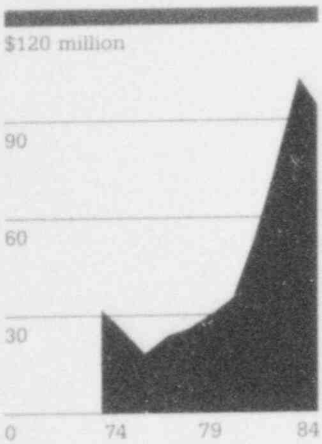
Nuclear Commitment Continues

EUA's support of nuclear power spans almost three decades. Energy produced by the System's interests in five of the nuclear generating units now on-line in New England has served to lessen the effect of high oil prices and aided in holding down EUA's overall cost of providing electric service.

We remain committed to using economical and reliable sources of nuclear power to fill base load capacity needs and further displace high-cost oil. Costs associated with the Millstone No. 3 and Seabrook No. 1 nuclear units are closely monitored. Economic analyses of these two projects continue to reveal long-term benefits to our ratepayers.

Millstone No. 3 Unit 93% Complete

Construction of the 1150-megawatt Millstone No. 3 Unit progressed satisfactorily during 1984. By



Construction Expenditures: EUA System construction expenditures declined in 1984 and should continue to decline for the next several years.

year-end, the unit was 93% complete. Commercial service is scheduled for May 1986. Pre-operational testing is proceeding at full scale and fuel loading is expected to begin November 1, 1985.

In August 1984, Northeast Utilities, the principal owner, announced that the cost to complete Millstone No. 3 could rise 6% to 10% above the then-current estimate of $3.5 billion. Using the 10% figure, the new completion cost would be $3.9 billion. This increases Montaup's cash construction costs over the next two years by $14 million and has been reflected in our construction program. Montaup has a 4% interest in the unit.

Seabrook No. 1 Unit 83% Complete

Nineteen eighty-four was an unsettled year for the Seabrook Project. On March 1, 1984, Public Service Company of New Hampshire (PSNH), the lead participant, announced a dramatic increase in the estimated cash cost to complete the two Seabrook Units, as well as deferred in-service dates. During April 1984, construction on the 1150 megawatt Seabrook No. 1 Unit was substantially reduced and construction on Seabrook No. 2 was terminated, as a result of PSNH's inability to meet its construction payments. These events combined to trigger a series of joint owner actions which led ultimately to a dramatic change in the arrangements for completing the project. In our opinion these actions also have caused the Seabrook No. 2 Unit to be effectively cancelled.

In May 1984, the joint owners approved a comprehensive plan whereby each participant agreed to prearrange for its pro rata share of cash necessary to complete the Seabrook No. 1 Unit. The plan provides for alternative financing arrangements. Montaup is arranging a standby letter of credit to guarantee financing for its 2.9% share of Unit No. 1.

In June 1984, the joint owners unanimously approved, as a goal, the phased transfer of responsibility for the construction and operation of Seabrook to a new entity to be known ultimately as the New Hampshire Yankee Corporation. This transfer is subject to certain regulatory approvals. A seven-member Executive Committee of joint owners was also created to monitor the expenditure of funds and the progress of construction of Seabrook.

At the end of 1984, Seabrook No. 1 was approximately 83% complete. The current estimate to complete construction of the unit is $800 million of cash. This reflects a return to full construction in the second quarter of 1985. The joint owners have adopted for finance purposes a budget of $1.0 billion of cash to complete. This includes a contingency believed appropriate to achieve the target commercial operating date of late 1986.

Throughout New England, the feasibility of completing Seabrook No. 1 is receiving careful scrutiny by regulatory agencies and state officials. A consultant retained by the New England governors reported in May of 1984 that the completion of the Seabrook No. 1 Unit was economically viable.

Seabrook Regulatory Proceedings

Several state public utility commissions have convened hearings to investigate various economic and financial matters involving Seabrook No. 1. Decisions by the Vermont and Connecticut agencies support its expeditious completion. Hearings by the New Hampshire Public Utilities Commission and the Massachusetts Department of Public Utilities are expected to be completed early in 1985. Maine's Public Utilities Commission does not support continued participation by Maine utilities and has attempted to order the sale of the Maine utilities ownership in Seabrook No. 1 and their disengagement from the project. Several Seabrook joint owners set in motion a course of action to seek, if necessary, court enforcement of the Maine utilities' contractual obligation under the Seabrook Joint Owners Agreement.

H*ydro Quebec Share Increased* – In 1984, New England utilities, through the New England Power Pool, reached an agreement in principle to expand their prior arrangement to import more low-cost Canadian hydroelectric power.

Phase 1, starting in 1986, calls for the delivery of three billion kilowatthours of hydroelectricity annually to New England. Under Phase 2, an additional seven billion kilowatthours will be delivered annually, starting in 1991.

EUA's share under Phase 1 is about 150 million kilowatthours per year; under Phase 2, another 350 million kilowatthours annually is added.

Hydro Quebec energy will further reduce our reliance on higher-priced oil.

Hydroelectric Plant Reactivated
Reactivation of Blackstone's 88-year-old hydroelectric generating plant in Pawtucket, Rhode Island was substantially completed in 1984. The new, fully automatic, turbine/generators became commercially operable in December 1984.

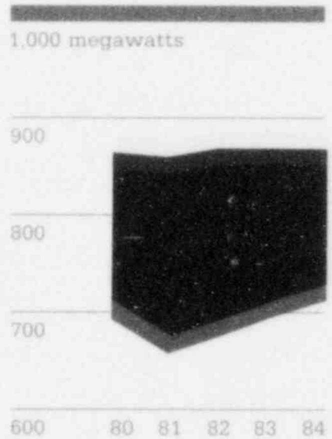
Coal Conversion Program Completed
The major construction for the conversion of two units at Montaup's Somerset station from oil to lower-cost domestic coal has been completed. The station is now burning coal but retains the ability to use oil as a fuel if price and national policy permit.

Full coal burning in both units, utilizing state-of-the-art pollution control equipment, commenced in mid-1984, a year ahead of schedule. Included as part of the pollution control equipment are a new wastewater treatment plant, two electrostatic precipitators, rebuilt ash-handling systems, a coal dust suppression system and an extensive noise abatement system. Tests have indicated that the station meets or exceeds all applicable state and federal environmental standards.

Burning coal will allow EUA to pass on to its customers annual savings based on the cost differential between oil and coal. During 1984, approximately 400,000 tons of coal were burned at Somerset, the equivalent of approximately 1,600,000 barrels of oil. The fuel cost savings were about $25 million.

Through the implementation of Montaup's Oil Conservation Adjustment rate (OCA), about one-third of this fuel cost saving was retained by Montaup to fund the cost of the conversion. After providing for taxes, the remainder, more than $8 million, were savings realized by customers. When the coal conversion has been fully paid for through OCA collection, all fuel cost savings will be passed on to customers.

Coal conversion completed. Fuel savings for 1984 were $25 million.



System Capability/ Peak:
- **System Capability**
- **Reserve Margin**
- **Peak Load**

Our reserve margin has remained relatively stable over the past five years and is expected to remain that way through 1992.

B*alanced Load Strategy* – EUA continues to pursue a balanced and integrated supply-side and demand-side strategy to meet future loads. Supply-side goals reflect decreased reliance on oil as a fuel and increased dependence on low-cost coal, hydro and nuclear power to establish an economic and reliable energy mix. Commitments to new capacity are prudently divided among a variety of sources, minimizing operating risks and financial exposure. Demand-side options include load management, conservation, cogeneration and small power producers. These alternatives moderate load growth, provide sources of renewable generation and increase the overall efficiency of capital and fuel resources, and form an integral part of EUA's overall power-planning process.

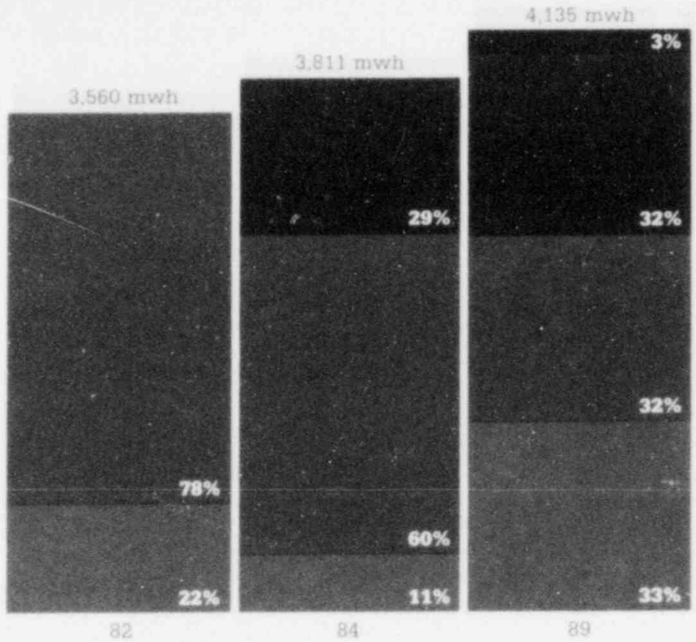
Progress in reaching a more desirable energy mix is evidenced by the fact that we have reduced our dependence on oil from 78% in 1982 to 60% in 1984, while increasing the use of lower-cost coal from 0% to 29% in the same time period.

The nuclear component of our 1984 energy mix was 11%, down from 22% in 1982. The reduction is principally the result of the nearly year-long unavailability of the Pilgrim No. 1 nuclear unit which was out of service for scheduled maintenance and for retrofitting required by the Nuclear Regulatory Commission. It is expected that 1985's energy mix will see oil further decreasing to about 41% of the total – with a corresponding increase in nuclear and coal generation.

By 1989, with the addition of new nuclear units and hydro-electric power, we expect our energy mix to be diversified to the extent that we are not largely dependent on any one fuel source. See Energy Mix Chart.

Y*ear in Review* – Ongoing efforts to expand and fine tune customer oriented programs continued throughout 1984. Focus was centered on the areas of: central operations, community relations and conservation.

Central Operations System Expansion
October 1984 marked one year of on-line use of the



Energy Mix:
mwh – megawatt hours
■ **Oil**
■ **Coal**
■ **Nuclear**
■ **Hydro**
In 1984, coal increased to 29%. As depicted for 1989, our goal is to diversify our energy mix so that we will not be dependent on any single fuel for our generation needs.

Supervisory Control and Data Acquisition system by the System Operations center.

System Operators have one of the most advanced systems in the country to continuously monitor and control the transmission of electricity to EUA's customers.

Plans are to expand and enhance the system in 1985 and include a data-link with Rhode Island, Eastern Massachusetts and Vermont Energy Control (REMVEC), one of the regional control centers of the New England Power Pool, of which EUA is a member.

The data-link interconnection between REMVEC and EUA's System Operations will allow for increased accuracy and speed of transmitted information on the status of EUA's generation and high-voltage transmission network.

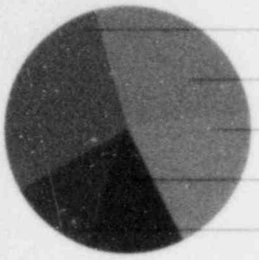
Community Relations – Communications a key to understanding.
Informal meetings with commmunity leaders were held in 1984. System executives met with elected officials and business and industrial leaders to discuss key issues. These meetings will be formalized in 1985 with the advent of "Community Leader Roundtables," which will build on the present foundation for ongoing dialogue between your System Companies and influential decision makers.

Educational Services and Speakers Club programs grew in 1984. Thousands of elementary students took part in electric safety programs. Additional thousands benefited from various educational films and publications distributed to schools.

The educational program was particularly enhanced by the formation of a Teachers Advisory Panel to provide guidance from professional educators. EUA also published a comprehensive *Educational Services Catalogue* which describes the System's programs and offers them to schools.

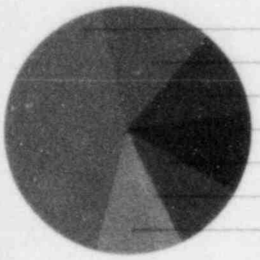
Community affairs, educational services and speakers club activities expanded.

Revenue



31.5¢	Residential
27.3¢	Commercial
19.6¢	Industrial
12.7¢	Other
8.9¢	Other Electric Utilities

Expense



42.5¢	Fuel
14.6¢	Other Operation and Maintenance
11.4¢	Purchased Power
10.7¢	Interest and Preferred Dividends
9.1¢	Taxes
3.9¢	Depreciation and Amortization
7.8¢	Earnings

Revenue/Expense Dollar: Fuel and Purchased Power were again our largest expense items. Cost control measures allowed us to keep the increase in Other Operation and Maintenance expenses at a manageable level.

The employees' volunteer Speakers Club responded to a record number of requests in 1984. Members addressed business and community leaders, students and social groups. They discussed energy issues, conservation and electric safety. As always, they served admirably as good-will ambassadors.

Conservation efforts continue.
In Rhode Island, Blackstone continued a multi-part program fostering the conservation of energy by encouraging the use of weatherization techniques, as well as the use of efficient electric-heating systems. Free weatherization kits were given to customers who received a residential energy-conservation audit.

In Massachusetts, Eastern Edison conducted an attic insulation program for residential customers. Eastern Edison arranged for energy audits and, through a neighborhood group-bid process with local contractors, also arranged for high-quality, lower-cost insulation work.

Executive Vice President Elected – Donald G. Pardus, Vice President of the Association since June 1979, was elected an Executive Vice President at the December 3, 1984 meeting of the Board of Trustees. Mr. Pardus retains his responsibilities as Chief Financial Officer and Treasurer.

Two labor contracts negotiated in 1983 continued in effect through 1984 and will not expire until the fall of 1985 and the spring of 1987. A union representation election was held in Blackstone. Since the majority of the employees voted against having union representation, we continue to state that more than 80% of the EUA System's employees are not represented by any bargaining unit.

The total number of EUA System employees at year-end was 1,075, up 4.8% from the end of 1983 – but still substantially below the peak employment level of 1,250 employees established in the early 1970s. The increase in the number of employees largely reflects an increasing demand for more specialized skills needed to provide cost-effective services to our customers.

[illegible]

[illegible] Visitors Association. The area is unique in pre-serving all the beauties of New England's heritage while it moves forward to a computer age. In that sense, the bypass territory is old and new at the same time. The residents — the families, the businessmen, the industrialists — link the new achievements to long-established values. With confidence that comes from past successes, these communities are thriving — moving toward greater prosperity by building on the past.

▲

Elmwood Sensors,
Pawtucket, R.I. – advanced
technology producing
thermal sensing devices.

Advanced technology. It's appropriate that an area which was the birthplace of the Industrial Revolution in America should also be home to a burgeoning advanced-technology industry. Over a recent five-year period, there was a 15 percent increase in the number of employees in this field. The companies manufacture such products as fiber optics, electric-conduction components, modems and sensitive thermostat devices. There are also computer centers for major corporations.

New Englanders build on the past. When business and industry grow, more work space is required. Within the EUA System territory, developers often find space by revitalizing factory complexes – updating the facility while keeping the historic charm – and creating new jobs and new opportunities for business.

Where looms once produced fabric, now live senior citizens. Restaurants now operate in buildings that were warehouses for the merchant trade. And, in factory complexes where manufacturers turned out an endless variety of products for worldwide trade, specialty stores now attract shoppers. Indeed, there are popular factory-outlet stores which exist hand-in-hand with the factories themselves.

Industrial and retail growth. It's a good time to be doing business. The food-production industry – including wholesale bakeries and dairies – is doing well. In one EUA service area the food-production industry increased electric-energy consumption by 39 percent each year from 1978 through 1983. The manufacture of scientific instruments is prospering, using an average of 13 percent more electricity each year during that same period. The paper, chemical, petroleum and rubber businesses also show growth, as does the manufacture of electric machinery.

Aetna Insurance Company's data processing center in Fall River, Mass. – part of a growing service industry.

New Englanders value their heritage – like this restored Victorian house in Fall River, Mass.

Condominium development in Easton, Mass. – new housing for a growing population.

In another direction, a national company – looking for a spot to locate its corporate headquarters – chose the System area; while one of the nation's largest toy manufacturers plans to build new headquarters here as well. Retail businesses are also booming – due to new malls, mill-outlet stores, retail shops, large department stores and new office space. Retail jobs rose more than 16 percent over a recent five-year period.

A place for people to prosper. For business to grow it needs people. And people need to live and prosper in an invigorating environment. The EUA service area embraces New England's heritage – its history, its architecture, its old mills, its cityscapes, its link to the sea, its hold on the land. EUA serves 646,000 residents – with their use of electricity representing one-third of the System's revenue. There's every type of housing – in every area. Mill villages. Picturesque, storybook towns. There are dense urban communities – with established neighborhoods. And new "mini-communities" –

▲ **Molded hulls at Boston Whaler, Rockland, Mass., one of the nation's premier boat-builders.**

Expanding retail commerce: equally at home in modern malls, converted mill outlet stores and small boutiques. ▼

high-rise apartments and condominiums. There's even a sprinkling of mansions. The communities are strong. There are four-year colleges and two-year community colleges. There is a rich cultural atmosphere – with symphony orchestras, theaters, active historical organizations and a highly respected art museum. And throughout the year – but most especially during New England's autumns – many communities hold festivals and fairs to celebrate art, craft, feasts and cultures.

A. T. Cross Co., Lincoln, R.I. – producers of precision writing instruments.

Tradition serves new needs. New England merchants continue their tradition of being able to serve the changing needs of the marketplace. Mirroring a time when clipper ships glided out of area yards to ply the oceans, there are companies which, today, produce sleek boats for the pleasure-craft trade. And, long-established companies prosper as well. There exists a vibrant shoe industry – one that dates to the nineteenth century – which is still an important component of the area economy. The service territory is also home to a leading pen-and-pencil company. In an age when the 19-cent pen has become commonplace, this uncommon manufacturer dazzles its clientele with prestigious writing instruments.

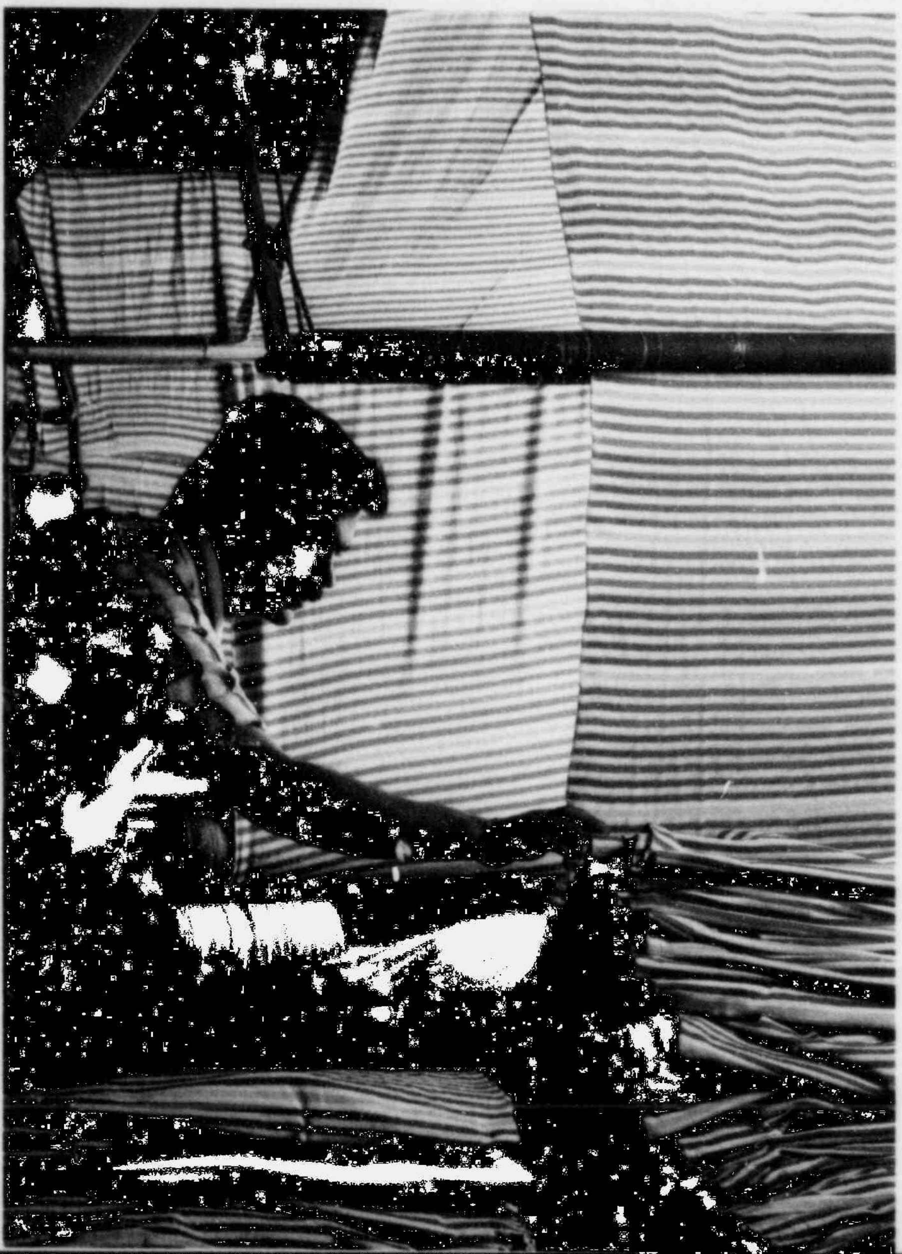
Stonehill College official discusses expansion of Easton, Mass. campus with an Eastern Edison engineer.

The battleship USS Massachusetts, Fall River, Mass. – symbol of our rising tourist industry.

Confidence. From toys, to shoes, to boats, to pens, to advanced technology – area businessmen look ahead with confidence, firmly in the forefront of their fields. It is a confidence that comes from experience – the New England attitude that in old accomplishments lies the foundation for the future. And the EUA System looks ahead with confidence as well – toward a bright future.

Pawtucket, R.I., home of the Red Sox Triple-A, International League champion farm team.

Health-tex, Inc. – with several plants in northern Rhode Island – provides fabrics to clothe our children.



Selected Consolidated Financial Data

Years Ended December 31, *(In Thousands Except Common Shares and Per Share Amounts)*	1984	1983	1982	1981	1980
Income Statement Data:					
Operating Revenues	**$361,325**	$302,450	$288,417	$297,931	$244,642
Operating Income	**46,767**	36,537	31,296	28,834	24,115
Consolidated Net Income	**30,053**	25,364	16,941	12,437	8,990
Balance Sheet Data:					
Plant in Service	**394,107**	374,132	358,599	348,255	333,812
Construction Work in Progress	**283,216**	249,700	172,057	109,348	82,308
Gross Utility Plant	**677,323**	623,832	530,656	457,603	416,120
Accumulated Depreciation	**134,077**	125,568	117,396	110,163	101,857
Net Utility Plant	**543,246**	498,264	413,260	347,440	314,263
Total Assets	**661,471**	585,135	489,259	426,821	390,958
Capitalization:					
Long-Term Debt	**288,876**	256,398	199,850	188,464	162,682
Redeemable Preferred Stock	**33,240**	34,155	34,457	19,906	20,199
Non-Redeemable Preferred Stock	**15,079**	15,079	15,079	15,079	15,079
Common Equity	**191,619**	172,327	140,973	109,875	95,424
Total Capitalization	**528,814**	477,959	390,359	333,324	293,384
Short-Term Debt	**0**	0	0	27,100	31,540
Common Stock Data:					
Earnings per Average Common Share	**2.85**	2.80	2.25	2.03	1.63
Average Number of Shares Outstanding	**10,562,324**	9,062,810	7,519,381	6,123,334	5,525,320
Return on Average Common Equity	**16.5%**	16.2%	13.5%	12.1%	9.5%
Market Price – High	**18**	18⅜	14⅝	12½	13¾
– Low	**12½**	13⅞	11	10⅛	10¼
– Year End	**18**	14⅞	14⅛	11⅜	11⅛
Cash Dividends Paid per Share	**1.91**	1.79	1.70	1.60	1.60

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

Overview

The financial results for 1984 reflect the EUA System's commitment to maintaining the improvement in its financial strength. Consolidated Net Income for 1984 increased 18.5% over 1983 and 1983 increased 49.7% over 1982. Earnings per average common share of $2.85 in 1984 increased 1.8% over 1983, while 1983 increased 24.4% over 1982. These increases in earnings per share are significant, considering the System has experienced increases in the number of average common shares outstanding of 16.5% and 20.5%, respectively.

Recognizing the EUA System's improved financial position, Standard & Poor's Corporation raised its credit rating on Eastern Edison's and Blackstone's first mortgage bonds from BBB to BBB + in December 1984.

Operating Revenues

The table below sets forth estimates of the factors which caused Operating Revenues to increase during the last two years:

($ in millions)	Increase (Decrease) From Prior Years 1984	1983
Operating Revenue change attributable to:		
Recovery of Fuel Costs	**$ 32.5**	$(14.0)
Effect of Rate Increases	**18.1**	24.0
Kwh Sales	**3.6**	5.7
Unit Contracts	**4.7**	(1.7)
Total	**$ 58.9**	$ 14.0

The revenues attributable to fuel costs are the result of the timely recovery of such costs through the operation of adjustment clauses.

The estimated effect of rate increases for the periods shown, reflect the billing of higher wholesale and retail rates of $16.4 million and $1.7 million, respectively, in 1984 and $17.1 million and $6.9 million, respectively, in 1983.

Kilowatthour sales improved during 1984 as a result of the continued strengthening of the economy. Weather conditions also influence kwh sales by their effect on air conditioning and heating loads. The 1983 summer air conditioning season was significantly hotter than 1984, while the 1983 winter heating season was colder than normal.

The table below sets forth the percent changes in kwh sales by class of customers for the last two years:

	Increase (Decrease) From Prior Years 1984	1983
Residential	**0.6%**	5.3%
Commercial	**0.9**	5.7
Industrial	**5.7**	4.9
Wholesale	**2.6**	5.8
Other	**4.0**	(3.6)
Consolidated	**2.4%**	3.7%

Expenses

The EUA System's most significant expense items are Fuel and Purchased Power costs, which comprised about 66.2% of total operating expenses for 1984. Fuel expense for 1984 increased $36.3 million or 28.4% over 1983, reflecting the higher net generation requirements of the System, while 1983 fuel expense decreased $9.4 million or 6.9% from 1982, as a result of the commencement during 1983 of burning lower cost coal in place of oil at Montaup's Somerset plant. Purchased Power-Demand costs increased $4.3 million and $6.8 million in 1984 and 1983, respectively, over prior periods as a result of increases in operating costs at several nuclear generating units in which the System has ownership interests or unit contracts. Other operation and maintenance expenses increased each year primarily as a result of the effects of inflation on labor, materials and other costs. In addition, the increases in other operation and maintenance expenses reflect increased costs related to the burning of coal at the Somerset plant.

Allowance For Funds Used During Construction (AFUDC) represents a non-cash element of income. AFUDC decreased $2.3 million in 1984 from 1983, primarily as a result of the inclusion in rate base of increased amounts of construction work in progress (CWIP), thereby reducing the base to which the AFUDC rate is applied and due to the discontinuance during 1984 of accruing AFUDC on our investment in the Seabrook No. 2 nuclear unit – on which construction was terminated in March 1984. The increase of $8.5 million in 1983 over 1982 reflected increased CWIP levels and was limited somewhat by increased CWIP in rate base.

Increases in total interest expense are reflective of the System's continuing need to borrow funds to meet those cash requirements of its construction program which cannot be met with internally generated funds.

Increases in long-term debt interest since 1982 reflect greater amounts of debt outstanding, mainly due to the permanent funding of short-term debt. (See Statement of Capitalization for details). Other Interest Expense decreased $1.6 million from 1983, and decreased $1.1 million in 1983 from 1982, primarily as a result of reduced levels of short-term borrowings.

Although inflation has subsided somewhat during 1984 it continues to have an impact on the operation of our System. At the Federal level, wholesale rate making practices permit a forward looking test period which enables us to anticipate inflationary increases. The traditional use of a historical test period for retail rate-making purposes at the state level does not provide us this opportunity. See "Supplementary Information to Disclose the Effects of Changing Prices" on page 32 for further financial information regarding the effects of inflation using measurement bases developed by the Financial Accounting Standards Board.

Financial Condition

The EUA System's need for permanent capital is primarily related to the construction of facilities required to meet the needs of its existing customers and to meet the future requirements of these customers as well as new customers. For 1984, 1983 and 1982, the EUA System's cash construction expenditures (excluding AFUDC), were $73.2 million, $78.9 million and $61.2 million, respectively.

The System expects cash construction expenditures to decrease to about $59.5 million in 1985 and to continue to decline for the next several years.

As is customary in the utility industry, cash construction requirements not met with internally generated funds are obtained through short-term borrowings which are ultimately funded with permanent capital. In 1984, internally generated funds amounted to $40.9 million, or 55.8% of the cash construction requirements. The remaining cash construction requirements were funded with proceeds from a previously completed financing or with short-term bank borrowings which were, ultimately, permanently financed. In 1983 and 1982, the EUA System was able to generate 34.5% and 20.7%, respectively, of its cash construction requirements with internally generated funds, with the balance coming from short-term borrowings. The System expects that in 1985 it will be able to generate internally in excess of 60% of its cash construction requirements.

Permanent financing during 1984 included a $40 million First Mortgage and Collateral Trust Bond issue (which was used to repay $35.8 million of outstanding debt), a $6.5 million tax-exempt bond issue and the issuance of 700,582 common shares ($9.4 million) through the EUA System's Dividend Reinvestment and Employee Share Ownership Plans.

The financing completed during 1984 and 1983 enabled the EUA System to end both years with no short-term bank borrowings. The ability to maintain reduced levels of short-term borrowings will depend on the System's ability to further increase the amount of funds generated internally.

Report of Management

The management of Eastern Utilities Associates is responsible for the consolidated financial statements and related information included in this annual report. The financial statements are prepared in accordance with generally accepted accounting principles applicable to rate-regulated utilities and include amounts based on the best estimates and judgments of management, giving appropriate consideration to materiality. Financial information included elsewhere in the annual report is consistent with the financial statements.

The EUA System maintains an accounting system and related system of internal controls which are designed to provide reasonable assurance as to the reliability of financial records and the protection of assets. The System's staff of internal auditors conducts reviews to maintain the effectiveness of internal control procedures.

Coopers & Lybrand, certified public accountants, is engaged to examine and express an opinion on our financial statements. Their examination includes a review of internal controls to the extent required by generally accepted auditing standards.

The Audit Committee of the Board of Trustees, which consists solely of outside Trustees, meets with management, internal auditors and Coopers & Lybrand to discuss auditing, internal controls and financial reporting matters. The internal auditors and Coopers & Lybrand have free access to the Audit Committee without management present.

Consolidated Income Statement

Years Ended December 31, *(In Thousands Except Numbers of Shares and Per Share Amounts)*	**1984**	1983	1982
Operating Revenues	**$361,325**	$ 302,450	$ 288,417
Operating Expenses:			
Fuel	**164,258**	127,898	137,308
Purchased Power-Demand	**43,902**	39,560	32,732
Other Operation	**45,639**	43,107	40,156
Maintenance	**10,764**	7,609	7,852
Depreciation and Amortization	**14,953**	14,571	13,379
Taxes – Other Than Income	**13,700**	12,950	14,143
Income and Deferred Taxes	**21,342**	20,218	11,551
Total Operating Expenses	**314,558**	265,913	257,121
Operating Income	**46,767**	36,537	31,296
Equity in Earnings of Nuclear Generating Companies	**1,428**	1,331	1,121
Allowance for Other Funds Used During Construction	**11,536**	12,684	6,657
Other Income – Net	**1,117**	751	152
Income Before Interest Charges	**60,848**	51,303	39,226
Interest Charges:			
Interest on Long-Term Debt	**34,470**	29,148	23,760
Other Interest Expense	**1,106**	2,691	3,764
Allowance for Borrowed Funds Used During Construction (Credit)	**(10,516)**	(11,713)	(9,203)
Net Interest Charges	**25,060**	20,126	18,321
Income After Interest Charges	**35,788**	31,177	20,905
Preferred Dividends of Subsidiaries	**5,735**	5,813	3,964
Consolidated Net Income	**$ 30,053**	$ 25,364	$ 16,941
Average Common Shares Outstanding	**10,562,324**	9,062,810	7,519,381
Consolidated Earnings Per Average Common Share	**$2.85**	$2.80	$2.25
Dividends Per Common Share	**$1.91**	$1.79	$1.70

Consolidated Retained Earnings Statement

Years Ended December 31, *(In Thousands)*	**1984**	1983	1982
Consolidated Retained Earnings – Beginning of Year	**$39,731**	$30,396	$26,137
Consolidated Net Income	**30,053**	25,364	16,941
Total	**69,784**	55,760	43,078
Dividends Paid – EUA Common Shares	**20,057**	16,029	12,682
Consolidated Retained Earnings – End of Year	**$49,727**	$39,731	$30,396

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

Consolidated Statement of Changes in Financial Position

Years Ended December 31, *(In Thousands)*	1984	1983	1982
Source of Funds			
Internally Generated:			
Income After Interest Charges	$ 35,788	$ 31,177	$ 20,905
Principal Non-Cash Charges (Credits) to Income:			
Depreciation	12,653	11,618	11,277
Amortization	3,103	3,450	3,223
Deferred Taxes	14,521	10,056	4,694
Investment Tax Credits, Net	5,835	7,635	5,565
Equity in Undistributed Earnings of Nuclear Generating Companies	(13)	(753)	(500)
Allowance for Funds Used During Construction	(22,052)	(24,397)	(15,860)
Funds from Operations	49,835	38,786	29,304
Proceeds from Oil Conservation Adjustment	16,815	10,314	
Less: Dividends Declared:			
EUA Common Dividends	(20,057)	(16,029)	(12,682)
Subsidiary Preferred Dividends	(5,735)	(5,813)	(3,964)
Internally Generated Funds	40,858	27,258	12,658
External Sources:			
Proceeds from Sale of Common Shares	9,443	22,239	26,975
Proceeds from Sale of Long-Term Debt – Net	66,081	61,019	24,000
Proceeds from Sale of Preferred Stock			15,000
Other – Net	3,602	5,140	2,418
Funds from External Sources	79,126	88,398	68,393
Total Source of Funds	$119,984	$115,656	$ 81,051
Application of Funds			
Construction Expenditures	$95,211	$103,309	$ 77,096
Less: Allowance for Funds Used During Construction	(22,052)	(24,397)	(15,860)
Cash Construction Expenditures	73,159	78,912	61,236
Decrease in Short-Term Debt			27,100
Retirement of Long-Term Debt	36,925	13,996	
Retirement of Preferred Stock	310	300	300
Increase (Decrease) in Working Capital	39	14,663	(10,454)
Other Application – Net	9,551	7,785	2,869
Total Application of Funds	$119,984	$115,656	$ 81,051
Changes in Components of Working Capital*			
Cash	$ 4,741	$ 264	$ (809)
Accounts Receivable	4,767	10,107	(4,546)
Materials and Supplies	(1,059)	3,884	3,152
Other Current Assets	435	117	(176)
Accounts Payable	(5,856)	5,711	(7,331)
Accrued Taxes	2,572	(3,690)	(73)
Other Current Liabilities	(5,561)	(1,730)	(671)
Increase (Decrease) in Working Capital	$ 39	$ 14,663	$ (10,454)

**(Excluding Short-Term Debt, Current Deferred Taxes and Redeemable Preferred Stock Sinking Fund Requirement)*

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

Consolidated Balance Sheet

December 31, *(In Thousands)*	1984	1983
Assets		
Utility Plant and Other Investments:		
Utility Plant		
In Service	$394,107	$374,132
Less Accumulated Provision for Depreciation	134,077	125,568
Net Utility Plant in Service	260,030	248,564
Construction Work in Progress	283,216	249,700
Net Utility Plant	543,246	498,264
Nonutility Property – Net	892	901
Investments in Nuclear Generating Companies	9,152	9,139
Other Investments (at cost)	69	69
Total Utility Plant and Other Investments	553,359	508,373
Current Assets:		
Cash and Temporary Cash Investments	5,305	564
Accounts Receivable:		
Customers, Less Allowance for Doubtful Accounts of $635,600 and $569,400, respectively	34,187	30,831
Accrued Unbilled Revenues	11,859	10,801
Other	960	608
Materials and Supplies (at average cost):		
Fuel	11,600	12,899
Plant Materials and Operating Supplies	5,893	5,653
Other Current Assets	823	387
Total Current Assets	70,627	61,743
Deferred Debits:		
Unamortized Debt Expense	5,853	5,734
Extraordinary Property Losses (Note I)	25,294	7,187
Other Deferred Debits	6,338	2,098
Total Deferred Debits	37,485	15,019
Total Assets	$661,471	$585,135
Liabilities and Capitalization		
Capitalization:		
Common Equity	$191,619	$172,327
Non-Redeemable Preferred Stock of Subsidiaries	15,079	15,079
Redeemable Preferred Stock of Subsidiaries – Net	33,240	34,155
Long-Term Debt – Net	288,876	256,398
Total Capitalization	528,814	477,959
Current Liabilities:		
Long-Term Debt Due Within One Year	1,125	4,458
Accounts Payable	26,011	20,154
Redeemable Preferred Stock Sinking Fund Requirement	856	309
Customer Deposits	1,837	1,799
Taxes Accrued	4,659	7,231
Deferred Taxes	3,046	3,240
Interest Accrued	9,982	5,749
Other Current Liabilities	4,828	3,537
Total Current Liabilities	52,344	46,477
Deferred Credits:		
Unamortized Investment Credit	27,089	21,254
Other Deferred Credits	951	104
Total Deferred Credits	28,040	21,358
Accumulated Deferred Taxes	52,273	39,341
Commitments and Contingencies (Note I)		
Total Liabilities and Capitalization	$661,471	$585,135

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

Consolidated Statement of Capitalization

December 31, *(Dollar Amounts in Thousands)*	1984		1983	
Eastern Utilities Associates:				
Common Shares:				
$5 par value, authorized 12,000,000 shares, outstanding, 10,892,886 shares in 1984 and 10,192,304 shares in 1983	$ 54,464		$ 50,962	
Other Paid-In Capital	89,345		83,406	
Common Shares Expense	(1,917)		(1,772)	
Retained Earnings	49,727		39,731	
Total Common Equity	191,619	36.2%	172,327	36.1%
Preferred Stock of Subsidiaries:				
Non-Redeemable Preferred:				
Blackstone Valley Electric Company:				
4.25%, $100 par value 35,000 shares (1)	3,500		3,500	
5.60%, $100 par value 25,000 shares (1)	2,500		2,500	
Premium	129		129	
Eastern Edison Company:				
4.64%, $100 par value 60,000 shares (1)	6,000		6,000	
8.32%, $100 par value 30,000 shares (1)	3,000		3,000	
Expense, Net of Premium	(50)		(50)	
	15,079	2.9	15,079	3.2
Redeemable Preferred:				
Eastern Edison Company:				
13.25%, $100 par value 150,000 shares (1)	15,000		15,000	
13.60%, $100 par value (2)	4,490		4,800	
15.48%, $100 par value 150,000 shares (1)	15,000		15,000	
Expense, Net of Premium	(327)		(331)	
Sinking Fund Requirement Due Within One Year	(923)		(314)	
	33,240	6.3	34,155	7.1
Long-Term Debt:				
Eastern Utilities Associates:				
Senior Notes 10¼% due 1999	21,375		22,500	
EUA Service Corporation:				
Notes Payable (Various Maturities at Money Market rates)	2,000		2,000	
Blackstone Valley Electric Company:				
First Mortgage Bonds:				
14¼% due 1995 (Series A)	30,000		30,000	
Variable Rate Demand Bonds due 2014	6,500			
Eastern Edison Company:				
First Mortgage and Collateral Trust Bonds:				
3⅜% due 1985			6,000	
12% due 1985 (second series)			19,800	
4⅝% due 1987	3,000		3,000	
13.9% due 1987 (second series)	10,000			
13.9% due 1987 (third series)	11,000			
14.2% due 1988 (second series)	19,000			
4⅜% due 1988	3,000		3,000	
14¼% due 1990	15,000		15,000	
17½% due 1991	30,000		30,000	
16⅞% due 1992	24,000		24,000	
4½% due 1993	5,000		5,000	
6½% due 1997	7,000		7,000	
8⅜% due 1999	5,000		5,000	
7⅞% due 2002	8,000		8,000	
8⅝% due 2003	10,000		10,000	
12¼% due 2013	40,000		40,000	
Pollution Control Revenue Bonds:				
10⅛% due 2008	40,000		20,419	
Note Payable due 1985 (Prime × 105%)			10,000	
Unamortized Premium	126		137	
	290,001		260,856	
Less Portion Due Within One Year	1,125		4,458	
Total	288,876	54.6	256,398	53.6
Total Capitalization	$528,814	100.0%	$477,959	100.0%

(1) Authorized and Outstanding.
(2) Authorized 60,000 shares. Outstanding 44,900 shares in 1984 and 48,000 shares in 1983.
The accompanying notes are an integral part of the financial statements.

Notes To Consolidated Financial Statements

December 31, 1984, 1983, and 1982

(A) Summary of Significant Accounting Policies:

General: Eastern Utilities Associates (EUA) and EUA Service Corporation (Service) are subject to the jurisdiction of the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935, and Service's accounts are maintained under the system of accounts prescribed by that Act. The accounting policies and practices of the retail subsidiaries, namely, Blackstone Valley Electric Company (Blackstone) and Eastern Edison Company (Eastern Edison), and of Montaup Electric Company (Montaup) are subject to regulation by the Federal Energy Regulatory Commission (FERC) and the respective state regulatory commissions with respect to their rates and accounting. The retail subsidiaries and Montaup conform with generally accepted accounting principles, as applied in the case of regulated public utilities, and conform with the accounting requirements and rate-making practices of the regulatory authority having jurisdiction.

Principles of Consolidation: The consolidated financial statements include the accounts of EUA and its subsidiaries (Blackstone, Eastern Edison, Montaup and Service). All material intercompany balances and transactions have been eliminated in consolidation.

Nuclear Generating Companies: Montaup follows the equity method of accounting for its investments in four regional nuclear generating companies. Montaup's investments in these companies range from 2.50 to 4.50 percent. Montaup is entitled to electricity produced from these facilities based on its ownership interests and is billed pursuant to contractual agreements which are approved by FERC.

Utility Plant: Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and material, allocable overhead, allowance for funds used during construction and indirect charges for engineering and supervision.

Depreciation of Utility Plant: For financial statement purposes, depreciation is computed on the straight-line method based on estimated useful lives of the various classes of property.

Provisions for depreciation, on a consolidated basis, were equivalent to a composite rate of approximately 3.2% in 1984, 1983 and 1982 based on the average depreciable property balances at the beginning and end of each year.

Operating Revenues: Revenues are based on billing rates authorized by applicable Federal and state regulatory commissions. The retail subsidiaries follow the policy of accruing the estimated amount of unbilled base rate revenues for electricity provided at the end of the month to more closely match costs and revenues. In addition they also accrue unrecovered fuel costs.

Federal Income Taxes: The general policy of EUA and its subsidiaries with respect to accounting for Federal income taxes is to reflect in income the estimated amount of taxes currently payable and to provide for deferred taxes on certain items subject to timing differences to the extent permitted by the various regulatory commissions. See Note B for details of major deferred tax items.

As permitted by the regulatory commissions it is the policy of the subsidiaries to defer the annual investment tax credits and to amortize these credits over the productive lives of the related assets.

Allowance for Funds Used During Construction: Allowance for funds used during construction (AFUDC) (a non-cash item) is defined in the applicable regulatory system of accounts as "the net cost during the period of construction of borrowed funds used for construction purposes and a reasonable rate upon other funds when so used."

The combined rate used in calculating AFUDC was 14.25% in 1984 and 14.00% in 1983 and 1982. In accordance with rate orders, Eastern Edison and Montaup provide deferred income taxes on the borrowed funds component of AFUDC.

(B) Income and Deferred Taxes:

Components of income and deferred tax expense for the years 1984, 1983 and 1982 are as follows:

(In Thousands)	1984	1983	1982
Federal:			
Current	$ 140	$ 725	$ 435
Deferred	13,187	9,070	4,455
Investment Tax Credit, Net	5,835	8,163	5,778
	19,162	17,958	10,668
State:			
Current	846	1,274	645
Deferred	1,334	986	238
	2,180	2,260	883
Charged to Operations	21,342	20,218	11,551
Charged to Other Income	455	417	133
Total	$21,797	$20,635	$11,684

Federal income tax expense was less than the amounts computed by applying Federal income tax statutory rates to book income subject to tax for the following reasons:

(In Thousands)	1984	1983	1982
Federal Income Tax Computed at Statutory Rates	$26,054	$23,196	$14,661
(Decreases) Increases in Tax From:			
Equity Component of AFUDC	(5,307)	(5,835)	(3,062)
Excess Tax Depreciation	1,067	1,326	229
Other	(2,297)	(380)	(1,059)
Federal Income Tax Expense	$19,517	$18,307	$10,769

The provision for deferred taxes resulting from timing differences is comprised of the following:

(In Thousands)	1984	1983	1982
Excess Tax Depreciation	$ 1,758	$ 2,076	$ 1,282
Computer Conversion Costs		(33)	(120)
Estimated Unbilled Revenue	(173)	704	969
Unbilled Purchased Power Costs			(1,702)
Unbilled Fuel Costs	(741)	1,347	373
Debt Component of AFUDC	4,817	5,078	3,978
Abandonment Losses	6,562	(847)	(806)
Capitalized Overheads	1,022	757	481
Effect of State and Local Taxes	1,334	986	238
Other – Net	(58)	(12)	1
Total	$14,521	$10,056	$ 4,694

The tax effect of the cumulative amount of timing differences at December 31, 1984 for which deferred Federal income taxes have not been provided, is approximately $18 million. This amount has not been recorded because the regulatory process is expected to allow such amounts to be recovered from customers when the taxes are ultimately payable.

(C) Capital Stock:

The changes in the number of common shares outstanding and the increases in other paid-in capital during the years ended December 31, 1984, 1983 and 1982 were as follows (dollars in thousands):

	Number of Common Shares Issued				
Year	Dividend Reinvestment and Employee Plans	Public Sales	Total	Increase In Common Shares At Par	Increase In Other Paid-In Capital
1984	**700,582**	–	**700,582**	**$ 3,502**	**$ 5,940**
1983	403,313	1,000,000	1,403,313	7,017	15,223
1982	324,431	1,800,000	2,124,431	10,622	16,353

In the event of involuntary liquidation the non-redeemable preferred stock of Blackstone and Eastern Edison is entitled to $100 per share. In the event of voluntary liquidation, or if redeemed at the option of those companies, the non-redeemable preferred stock is entitled to: Blackstone's 4.25% issue, $104.40; Blackstone's 5.60% issue, $103.82; Eastern Edison's 4.64% issue, $102.98; Eastern Edison's 8.32% issue, $105.62, prior to October 1, 1988 and at reduced premiums in subsequent years.

Under the terms and provisions of the issues of preferred stock of Blackstone and Eastern Edison, certain restrictions are placed upon the payment of dividends on common stock by each company. At December 31, 1984 and 1983, the respective capitalization ratios were in excess of the minimum which would make these restrictions effective.

(D) Redeemable Preferred Stock:

Eastern Edison's 13.60%, 15.48% and 13.25% Preferred Stock issues are entitled to mandatory sinking funds sufficient to redeem 3,000, 6,000 and 7,500 shares, respectively, during each twelve-month period, commencing: October 1, 1980 in the case of the 13.60% issue, October 1, 1985 in the case of the 15.48% issue and January 31, 1989 in the case of the 13.25% issue. The redemption price for each issue is equal to the initial public offering price ($104.615, $101.50 and $100, respectively) plus accrued dividends. Eastern Edison also has the non-cumulative option of redeeming an additional 3,000, 6,000 and 7,500 shares, respectively, during each period at such price. In the case of the 13.25% issue, if Eastern Edison does not exercise its option of redeeming an additional 7,500 shares the holders of that preferred stock have the right to exercise such option.

In the event of involuntary liquidation the redeemable preferred stock of Eastern Edison is entitled to $100 per share. In the event of voluntary liquidation, or if redeemed at the option of Eastern Edison, the 13.60% and 15.48% issues of redeemable preferred stock are entitled to $114.82 and $116.98, respectively, prior to October 1, 1985; the 13.25% issue is entitled to $112.10 prior to January 31, 1986. The redemption premium reduces in subsequent years.

The aggregate amount of redeemable preferred stock sinking fund requirements for each of the five years following 1984 are: $923,000 in 1985, 1986, 1987, 1988 and $1,673,000 in 1989.

(E) Retained Earnings:

Under the provisions of EUA's Senior Note Agreements, Retained Earnings in the amount of $42,249,347 as of December 31, 1984 were unrestricted as to the payment of cash dividends on EUA Common Shares.

Under provisions of the Indentures securing the various bond issues of the retail subsidiaries, Retained Earnings in the amount of $4,310,745 in the case of Blackstone and $24,830,834 in the case of Eastern Edison, as of December 31, 1984, were unrestricted as to the payment of cash dividends on their Common Stock.

(F) Long-Term Debt:

Under terms of the Indentures securing their various bond issues the retail subsidiaries are required to deposit annually with their respective Trustee cash in an amount equal to: 1% of the aggregate principal amount of bonds previously authenticated and delivered, in the case of Eastern Edison and 2.25% of the average gross investment in depreciable property, in the case of Blackstone.

The retail subsidiaries have satisfied sinking fund requirements for 1984 under alternate provisions of their respective Indentures by certifying to the Trustee "available property additions."

The various first mortgage bond issues of the retail subsidiaries are secured by substantially all of their utility plant. In addition, Eastern Edison's bonds are collateralized by securities of Montaup in the principal amount of $300,185,400.

Eastern Edison has accounted for the early extinguishment of a series of its First Mortgage and Collateral Trust Bonds due in 1985 by placing the funds necessary to satisfy all debt requirements of the Bonds in an irrevocable Trust in accordance with Statement of Financial Accounting Standards No. 76.

In December 1984 Blackstone issued $6,500,000 Variable Rate Demand Bonds due 2014. This series was issued with the collateral of an irrevocable letter of credit which expires on December 1, 1989. The letter of credit agreement permits extensions on an annual basis upon mutual agreement of the bank and Blackstone. The weighted average interest rate on the Demand Bonds for 1984 was 6.78%.

The aggregate amount of EUA System cash sinking fund requirements and maturities for long-term debt for each of the five years following 1984 are: $1,125,000 in 1985, $4,125,000 in 1986, $28,125,000 in 1987, $26,125,000 in 1988 and $4,125,000 in 1989.

(G) Lines of Credit:

EUA System companies had unused short-term lines of credit with various banks of approximately $47,000,000 at December 31, 1984. In accordance with informal agreements with the various banks, commitment fees are required to maintain the lines of credit.

(H) Jointly-Owned Facilities:

At December 31, 1984, Montaup owned the following interests in jointly-owned electric generating facilities (dollars in thousands):

Unit	Percent Owned	Plant in Service	Accumulated Depreciation	Net Plant in Service	Construction Work in Progress
Canal No. 2	50.00%	$64,471	$20,111	$44,360	$ 73
Wyman No. 4	1.96	3,978	716	3,262	
Seabrook No. 1	2.90	62	9	53	100,167
Millstone No. 3	4.01				138,398

The foregoing amounts represent Montaup's interest in each facility. Financing for any such interest is provided by Montaup. Montaup's share of related operating and maintenance expenses is included in its corresponding operating expenses.

See Note I for information with respect to recent developments affecting the Seabrook project, including the termination of construction on the Seabrook No. 2 nuclear generating unit.

(I) Commitments and Contingencies:

Pensions: The EUA System companies participate in a pension plan covering substantially all of their employees. The total pension expense charged to operations, which includes amortization of past service costs over 20 years, amounted to approximately $1,461,000, $1,408,000 and $1,942,000 for the years ended 1984, 1983 and 1982, respectively. The EUA System companies make annual contributions to the plan equal to the amounts accrued for pension expense. The accumulated plan benefits and plan net assets for the Employees' Retirement Plan of Eastern Utilities Associates and its Subsidiary Companies are presented below.

(In Thousands)	**January 1, 1984**	January 1, 1983
Actuarial Present Value of Accumulated Plan Benefits:		
Vested	**$30,800**	$26,697
Nonvested	**1,862**	1,544
	$32,662	$28,241
Market Value of Net Assets Available for Benefits	**$46,995**	$40,697

The assumed rate of return used in determining the actuarial present value of the accumulated plan benefits was 8.0% for 1984 and 1983.

Certain health care benefits are provided to substantially all retired employees. The cost of these benefits, which amounted to approximately $550,000 in 1984, is charged to expense when paid.

Long-Term Purchased Power Contracts: The EUA System is committed under long-term purchased power contracts, expiring on various dates through the year 2007, to pay demand charges whether or not energy is received. Under terms in effect at December 31, 1984, the aggregate annual minimum commitments for such contracts is approximately $50,000,000 for each year through 1987, $46,000,000 in 1988 and 1989 and will aggregate $664,000,000 for years after 1989. In addition, the EUA System is required to pay additional amounts depending on the actual amount of energy received under such contracts. The demand costs associated with these contracts are reflected as Purchased Power-Demand on the Consolidated Income Statement.

Construction: The EUA System's construction program is estimated at $82,000,000 for the year 1985 and $185,000,000 for the years 1985 through 1989 (including allowance for funds used during construction).

Seabrook: Montaup has a 2.90% ownership interest in the 1150 megawatt Seabrook No. 1 nuclear generating unit being constructed in Seabrook, New Hampshire. All of the necessary state and Federal regulatory approvals for the construction of the unit have been obtained, but further appeals are possible.

The Seabrook No. 1 unit has experienced substantial cost increases due to, among other things, outside intervention in various proceedings, design changes, revisions of Nuclear Regulatory Commission regulations, extraordinarily high interest rates, inflation and construction delays. The largest participant in the unit is Public Service Company of New Hampshire (PSNH) which owns a 35.6% ownership interest. On March 1, 1984, PSNH announced that the estimated cost of Seabrook No. 1 would increase by $1.5 billion, over its November 1982 estimate, to $4.5 billion and its estimated in-service date would be delayed 18 months until July 1986.

In mid-April 1984, PSNH announced that it was experiencing a severe liquidity crisis and ceased payment of its share of Seabrook construction costs. As a result of this action, activity at the Seabrook project was significantly reduced until early July 1984 when PSNH obtained additional financing. Expenditures were increased to a level averaging $4 million per week at that time, and to $5 million a week in early December 1984.

As part of a plan to assure completion of Seabrook No. 1, each Seabrook Joint Owner was required to develop a financing plan for assuring that sufficient funds would be available to pay for its proportionate share of the estimated $1 billion remaining cash cost to complete the unit. Montaup is arranging an irrevocable standby letter of credit to assure compliance with its 2.90% commitment to complete Seabrook No. 1.

Most of the Joint Owners are involved in various regulatory proceedings with respect to Seabrook. Such proceedings are reviewing individual company financing plans for Seabrook as well as the desirability of further participation in the project. Montaup is not a party to any of these proceedings.

If, due to regulatory action, financial difficulties or any other reason, one or more of the other Seabrook Joint Owners should be unable or unwilling to fulfill their contractual commitment to pay on a timely basis their share of Seabrook No. 1 construction costs, completion of the unit could be jeopardized.

Montaup is unable to predict the timing or outcome of any of the various regulatory proceedings, or what effect regulatory actions, or any financing difficulties of any participant, may have on the cost of completion of Seabrook No. 1 or on Montaup. Further delays in the in-service date of Seabrook No. 1 would increase the ultimate cost of the unit.

Montaup also has a 2.90% ownership interest in the Seabrook No. 2 nuclear generating unit. In March 1984, the Seabrook Joint Owners voted to halt construction on the unit. In Montaup's opinion, this action has effectively cancelled the Unit. As of March 31, 1984, Montaup had incurred approximately $22,710,000 of costs (including AFUDC) in connection with Seabrook No. 2. Montaup has received an accounting order from the FERC staff permitting it to record the costs of the abandoned project as an extraordinary property loss and to amortize these costs, net of related tax savings. In addition, in December 1984, FERC approved, effective June 6, 1985, and on a subject-to-refund basis, Montaup's $17.6 million rate increase request which was filed in November 1984. This filing included Montaup's request for recovery, over a ten year period, of all of its costs associated with Seabrook No. 2, including those referred to above. In accordance with FERC practice, recovery of Montaup's investment will not include any return on the unamortized portion of such costs. Certain parties have intervened in Montaup's rate proceeding before FERC and are contesting Montaup's recovery of its investment in Seabrook No. 2.

Montaup believes that FERC will continue its past practice of permitting recovery, through rates, of all costs related to completed as well as cancelled projects, so long as such costs were prudently incurred. In Montaup's opinion, all of its costs related to the Seabrook units have been prudently incurred and therefore will ultimately be recovered through rates.

Revenues Subject to Refund: At December 31, 1984, approximately $39,000,000 of Montaup's revenue collected since November 1981 is subject to possible refund. Of that amount approximately $15,400,000, $10,800,000, and $11,700,000 relates to 1984, 1983 and 1982, respectively. Montaup believes that any amounts which may ultimately be refunded will not have a material effect on the financial statements.

Guarantees: Montaup and the other stockholders of Vermont Yankee Nuclear Power Corporation have guaranteed their respective pro rata shares (2.5% in the case of Montaup) of a $40,000,000 nuclear fuel financing. In addition, Montaup along with the other stockholders of Connecticut Yankee Atomic Power Company have guaranteed their respective pro rata shares (4.5% in the case of Montaup) of a bank line of credit of up to $50,000,000 and a debenture bond issue of $50,000,000.

Auditors' Report

To the Trustees and Shareholders of Eastern Utilities Associates:

We have examined the consolidated balance sheet and consolidated statement of capitalization of Eastern Utilities Associates and subsidiaries as of December 31, 1984, and the related consolidated statements of income, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances. The financial statements of Eastern Utilities Associates and subsidiaries for the years ended December 31, 1983 and 1982, were examined by other auditors, whose report, dated March 2, 1984, expressed an unqualified opinion on those statements.

In our opinion, the 1984 financial statements referred to above present fairly the consolidated financial position of Eastern Utilities Associates and subsidiaries as of December 31, 1984 and the consolidated results of their operations and changes in their financial position for the year then ended, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Coopers & Lybrand

Boston, Massachusetts
March 1, 1985

Quarterly Financial and Common Share Information

(Unaudited)

	Operating Revenues	Operating Income	Income After Interest Charges	Consolidated Net Income	Earnings per Average Common Share	Dividends Paid	Common Share Market Price High	Common Share Market Price Low
For the quarters ended 1984:		thousands						
December 31	$87,977	$11,533	$8,709	$7,277	$0.67	$0.485	18	12½
September 30	$88,591	$12,548	$9,831	$8,397	$0.79	$0.485	15¾	13½
June 30	$90,281	$10,284	$7,465	$6,031	$0.58	$0.485	13¾	13
March 31	$94,477	$12,403	$9,783	$8,347	$0.81	$0.455	14⅞	14
For the quarters ended 1983:								
December 31	$84,474	$ 9,023	$7,777	$6,333	$0.67	$0.455	18⅜	14½
September 30	$73,015	$10,207	$8,587	$7,134	$0.79	$0.455	17¼	15¼
June 30	$64,266	$ 7,548	$6,313	$4,861	$0.54	$0.455	16¾	14⅝
March 31	$80,695	$ 9,760	$8,501	$7,036	$0.80	$0.425	15¾	13⅞

The common shares of Eastern Utilities Associates are listed on the New York Stock Exchange under the ticker symbol "EUA". The approximate number of Common Shareholders of record on February 1, 1985 was 23,800.

Supplementary Information To Disclose The Effects of Changing Prices

(Unaudited)

The following supplementary information is supplied in accordance with the requirements of the Statement of Financial Accounting Standards No. 33 (as amended) to provide certain information about the effects of changing prices. It should be viewed as an estimate of the approximate effect of inflation, rather than a precise measure.

Current cost amounts, as measured by the Handy-Whitman Index of Public Utility Construction Costs, reflect changes in specific prices of plant from the date the plant was acquired to the present. Since utility plant would not be replaced precisely in kind, current cost does not represent the replacement cost of the System's productive capacity.

Depreciation was computed by applying the current depreciation rates to the respective indexed plant amounts.

Fuel inventories, the cost of fuel used in generation and purchased power for resale have not been restated from their historical cost. Regulation limits the recovery of fuel and purchased power costs through the operation of adjustment clauses.

As prescribed in Financial Accounting Standard No. 33, income taxes were not adjusted.

Under the rate-making practices prescribed by the regulatory commissions to which the System companies are subject, only the historical cost of plant is presently recoverable in rates as depreciation. The excess cost of plant that exceeds historical cost is not presently recoverable in rates as depreciation and is reflected as a reduction to net recoverable cost. The gain from the decline in purchasing power of net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance property, plant, and equipment. Since the depreciation on this plant is limited to the recovery of historical costs, the System companies do not have the opportunity to realize a holding gain on debt and are limited to recovery only of the embedded cost of debt capital.

Consolidated Statement of Income Adjusted for Changing Prices
For the year ended December 31, 1984

(Thousands of Dollars)	Current Cost
Effect on the following if utility plant adjustments are made:	
Depreciation, as adjusted	$ 37,683
Income After Interest Charges, as adjusted	$ 10,758
Increase in Specific Prices of Utility Plant Held During the Year*	$ 24,087
Adjustment to Net Recoverable Cost	19,930
Effect of Increases in General Price Level	(38,969)
Excess of Increase in General Price Level Over Increase in Specific Prices After Adjustment to Net Recoverable Cost	(5,048)
Gain From Decline in Purchasing Power of Net Amounts Owed	17,462
Net	$ 12,414

*At December 31, 1984, the current cost of net utility plant was $1,003,015 while historical cost or net cost recoverable through depreciation was $543,246.

Five Year Summary of Selected Financial Data Adjusted for the Effects of Changing Prices

Years Ended December 31, *(In Thousands of Average 1984 Dollars)*	**1984**	1983	1982	1981	1980
Operating Revenues	**$361,325**	$317,572	$312,579	$342,746	$310,584
Current Cost Information:					
Income (Loss) After Interest Charges*	10,758	10,111	(546)	(3,085)	(1,781)
Income (Loss) Per Common Share After Preferred Dividend Requirements*	0.48	0.47	(0.60)	(1.14)	(0.70)
Excess Of Increase In General Price Level Over Increase In Specific Prices After Adjustment To Net Recoverable Cost	(5,048)	(4,919)	(7,758)	5,710	25,224
Net Assets at Year-End At Net Recoverable Cost	239,938	232,639	204,138	161,262	158,481
General Information:					
Gain from Decline In Purchasing Power Of Net Amounts Owed	17,462	9,389	8,637	19,156	25,328
Cash Dividends Paid Per Common Share	1.91	1.88	1.84	1.84	2.03
Market Price Per Common Share At Year End	18.00	15.62	15.31	13.09	14.13
Average Consumer Price Index	312.0	298.4	289.1	272.4	246.8

*Before Adjustment to Net Recoverable Cost.

Consolidated Operating Statistics

Years Ended December 31,	1984	1983	1982	1981	1980	1979	1974
Energy Generated and Purchased (millions of kwh):							
Generated – by Somerset Station	**1,180**	1,123	738	940	1,041	792	1,643
– by Nuclear Units	**458**	1,019	861	869	733	1,012	420
– by Jointly-Owned Units	**1,507**	1,724	1,632	1,784	1,746	1,795	–
– by Life of the Unit Contracts	**814**	452	706	675	757	706	760
Interchange with NEPOOL	**(136)**	(285)	(49)	(240)	(263)	(600)	367
Purchased Power – Unit Power	**480**	168	161	240	319	410	480
Total Generated and Purchased	**4,303**	4,201	4,049	4,268	4,333	4,115	3,670
Operating Revenues (thousands):							
Residential	**$121,623**	$104,101	$ 97,161	$ 94,217	$ 79,357	$ 63,394	$ 47,803
Commercial	**105,310**	89,225	83,519	82,515	67,377	53,012	33,163
Industrial	**75,850**	58,901	56,468	60,486	48,931	38,192	28,380
Other Electric Utilities	**23,909**	16,212	18,289	22,770	18,183	12,435	11,737
Other	**9,396**	13,463	10,761	9,081	7,886	7,502	5,159
Total Primary Sales Revenues	**336,088**	281,902	266,198	269,069	221,734	174,535	126,242
Unit Contracts	**25,237**	20,548	22,219	28,862	22,908	11,266	4,343
Total Operating Revenues	**$361,325**	$302,450	$288,417	$297,931	$244,642	$185,801	$130,585
Energy Sales (millions of kwh):							
Residential	**1,205**	1,197	1,137	1,122	1,149	1,150	1,052
Commercial	**1,113**	1,103	1,044	1,055	1,058	1,052	792
Industrial	**856**	810	772	841	848	859	830
Other Electric Utilities	**396**	386	365	431	420	398	519
Other	**30**	34	36	38	42	44	45
Total Primary Sales	**3,600**	3,530	3,354	3,487	3,517	3,503	3,238
Losses and Company Use	**215**	201	206	196	230	226	215
Total System Requirements	**3,815**	3,731	3,560	3,683	3,747	3,729	3,453
Unit Contracts	**488**	470	489	585	586	386	217
Total Energy Sales	**4,303**	4,201	4,049	4,268	4,333	4,115	3,670
Number of Customers:							
Residential	**211,622**	209,678	207,702	205,894	204,221	201,435	193,110
Commercial	**22,177**	21,605	21,133	20,732	20,380	20,073	20,311
Industrial	**1,209**	1,189	1,210	1,213	1,219	1,222	1,655
Other Electric Utilities	**16**	12	18	14	17	16	12
Other	**29**	31	31	34	30	150	241
Total Customers	**235,053**	232,515	230,094	227,887	225,867	222,896	215,329
Average Revenue per Residential Customer ($)	**575**	496	468	458	389	315	249
Average Use per Residential Customer (kwh)	**5,694**	5,708	5,474	5,449	5,626	5,708	5,448
Average Revenue per kwh:							
Residential	**10.09¢**	8.70¢	8.55¢	8.40¢	6.91¢	5.52¢	4.54¢
Commercial	**9.46¢**	8.09¢	7.99¢	7.82¢	6.37¢	5.04¢	4.19¢
Industrial	**8.86¢**	7.27¢	7.31¢	7.20¢	5.77¢	4.44¢	3.42¢

Consolidated Operating Statistics – General

Years Ended December 31,	**1984**	1983	1982	1981	1980	1979	1974
Capitalization (thousands):							
Bonds (Net)	**$266,500**	$226,219	$165,950	$155,964	$125,182	$ 80,985	$ 65,023
Other Long-Term Debt	**22,376**	30,179	33,900	32,500	37,500	42,500	3,400
Total Long-Term Debt	**288,876**	256,398	199,850	188,464	162,682	123,485	68,423
Preferred Stock	**48,319**	49,234	49,536	34,985	35,278	20,686	15,069
Common Equity	**191,619**	172,327	140,973	109,875	95,424	93,765	50,017
Total Capitalization	**$528,814**	$477,959	$390,359	$333,324	$293,384	$237,936	$133,509
Common Share Data:							
Earnings per Average Common Share ($)	**2.85**	2.80	2.25	2.03	1.63	1.74	1.56
Dividends per Share ($)	**1.91**	1.79	1.70	1.60	1.60	1.60	1.50
Payout (%)	**67.0**	63.9	75.6	78.8	98.2	92.0	96.2
Average Common Shares Outstanding	**10,562,324**	9,062,810	7,519,381	6,123,334	5,525,320	4,871,667	2,784,945
Total Common Shares Outstanding	**10,892,886**	10,192,304	8,788,991	6,664,560	5,583,634	5,438,969	2,784,945
Book Value per Share ($)	**17.59**	16.91	16.04	16.49	17.09	17.24	17.99
Percent Earned On Average Common Equity (%)	**16.5**	16.2	13.5	12.1	9.5	9.4	8.7
Market Prices ($):							
High	**18**	18⅜	14⅝	12½	13¾	15½	17
Low	**12½**	13⅞	11	10⅛	10¼	11⅝	8
Year End	**18**	14⅞	14⅛	11⅜	11⅛	11¾	8⅜
Miscellaneous ($ in thousands):							
Total Construction Expenditures ($)	**95,211**	103,309	77,096	54,436	34,939	30,498	32,441
Cash Construction Expenditures ($)	**73,159**	78,912	61,236	41,745	25,024	24,230	29,169
Internally Generated Funds as a % of Cash Construction (%)	**55.8**	34.5	20.7	22.5	4.5	26.7	12.0
Installed Capability – MW	**931**	931	927	927	940	996	885
Less: Unit Contract Sales – MW	**75**	75	70	80	88	88	63
System Capability – MW	**856**	856	857	847	852	908	822
System Peak Demand – MW	**716**	700	680	661	695	677	590
Reserve Margin (%)	**19.5**	22.3	26.0	28.1	22.7	34.1	39.3
System Load Factor (%)	**60.6**	60.8	59.8	63.6	61.5	62.8	64.5
Sources of Energy (%):							
Nuclear	**10.9**	23.8	22	20.6	17.0	21.9	18.4
Coal	**29.3**	16.3					
Oil	**59.8**	59.9	77.8	79.4	83.0	78.1	81.6
Cost of Fuel (Mills Per kwh):							
Nuclear	**8.9**	6.5	6.3	5.4	4.9	3.5	2.4
Coal	**27.8**	21.6					
Oil	**43.6**	41.5	41.5	47.0	35.3	25.1	20.2
All Fuels Combined	**36.1**	30.7	34.1	39.0	30.8	19.6	16.8

Dividend Reinvestment and Common Share Purchase Plan

A Dividend Reinvestment and Common Share Purchase Plan is available to all registered shareholders and System company employees.

Participants in the Plan are given a 5% discount on shares purchased with reinvested dividends. Participants may also make additional cash payments as frequently as once a month to purchase additional shares with no discount. Optional cash payments are limited to a maximum of $5,000 per calendar quarter and must be received not later than the 5th day preceding the Investment Date to be invested in that month.

The Economic Recovery Tax Act of 1981 provides special tax treatment through the end of 1985 to individual shareholders who reinvest their dividends under EUA's Plan. Individual shareholders are eligible to exclude from their income, for Federal income tax purposes, up to $750 annually ($1,500 on a joint return) of qualified reinvested dividends.

The Investment Date for all shares purchased under the Plan is the dividend payment date for the months in which dividends are payable. For each month in which a dividend is not payable the Investment Date is the 15th of such month. The price of shares purchased is based on the average closing price of EUA shares for the five trading days preceding each investment date.

Complete details regarding the Plan may be obtained by writing:
The First National Bank of Boston
EUA Automatic Dividend
Reinvestment Plan
Post Office Box 1681
Boston, MA 02105

Transfer Agent

The First National Bank of Boston
Post Office Box 644
Boston, MA 02102
(Common and Preferred Shares)

Bond Trustee

State Street Bank and Trust Company
225 Franklin Street
Boston, MA 02110
(Bonds of all series)

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(401) 333-1400
William R. Bisson, *President*

The name Eastern Utilities Associates is the designation of the Trustees for the time being under a Declaration of Trust dated April 2, 1928, as amended, and all persons dealing with Eastern Utilities Associates must look solely to the trust property for the enforcement of any claims against Eastern Utilities Associates as neither the Trustees, Officers nor Shareholders assume any personal liability for obligations entered into on behalf of Eastern Utilities Associates.

Annual meeting

The 1985 Annual Shareholders Meeting will be held on Monday, April 22, 1985 at 10 a.m. in the Board Room on the 33rd Floor at State Street Bank and Trust Company, 225 Franklin Street, Boston, Massachusetts.

84

ANNUAL REPORT

PSNH

Public Service of New Hampshire

Dear Shareowner:

Last April I wrote to you and stated that the events surrounding the Company's financial position at that time were the most serious challenges ever faced by PSNH.

Through the sacrifice of employees and shareowners alike, the Company has overcome many of the serious challenges we faced during 1984. Working together, we have taken some substantial steps in our efforts to restore the financial health of the Company. As a result, today we are better able to face the remaining challenges to a more stable and secure future for PSNH, but much remains to be done.

I would like to take this opportunity to review key events in 1984 and relate the positive changes that have taken place.

In the spring of 1984, facing a serious cash crisis, we instituted a number of measures in order to maintain PSNH's corporate existence. Two critical measures taken were the cessation of payments by the Company to the Seabrook project and, on April 18, 1984, halting construction of the project. Other measures included halting construction on the oil-to-coal conversion project at Schiller Station, implementing a plan to reduce the PSNH workforce, and reducing management salary levels. Finally, with great reluctance, the Board of Directors voted to omit dividends on shares of common and preferred stock of the Company.

In July, 1984 the Company was able to resume its Seabrook construction payments as well as construction on Seabrook Unit 1. Construction on that unit continues today at about half of the projected full construction level. Later in 1984, the Company resumed construction at Schiller Station and placed the first of three coal-burning units into operation in December. Through attrition and early retirements, the Company was also successful in reducing the number of employees at an annual savings of approximately $7.5 million. Other cost saving measures were also implemented, further reducing operating costs.

Much of what we accomplished in 1984 was also the result of our ability, with the assistance of Merrill Lynch Capital Markets, to complete two crucial financings. The first, a short-term financing of $90 million to provide an immediate cash infusion, was completed in June. We were also able, in June, to successfully restructure loan agreements with certain lenders. The second, a long-term financing completed in December, provided PSNH with approximately $275 million in cash proceeds for external cash operating funds.

Because of those financings, our successful efforts to reduce expenses, and the exemplary performance of all PSNH employees, the Company should now be able, with continued rigid control over cash flow, to operate without additional financing through 1986, when we expect Seabrook Unit 1 to be completed. In addition to the two financings in 1984, a subsequent financing will be necessary to satisfy our Seabrook Station obligations.

Unfortunately, because of our very tight cash position and restrictions placed upon the declaration and payment of dividends by the New Hampshire Public Utilities Commission, as well as restrictions contained in terms of certain loan agreements and the Company's Articles of Agreement, it has been necessary to omit dividends on shares of common and preferred stock.

While substantial strides have been made in the past year in bringing the Company back from the edge of bankruptcy, it is essential that shareowners understand that if the Company is to remain a viable corporate entity it must continue to conserve its cash reserves at least until the completion of Seabrook Unit 1. In this light, both the management and Board of Directors of the Company must continually weigh the need to provide a current return to equity holders against maintaining the long-term viability of our shareowners' investment. In that regard, we believe that the completion of Seabrook Unit 1 is the only realistic course of action to take to continue to preserve your investment. This belief has been a key factor in decisions that were made regarding the Seabrook project.

Despite the crisis we faced throughout the year, the continuation of safe, reliable service to our customers was essential. We asked our employees to excel in adversity and they responded beyond our expectations. Extremely good examples of their accomplishments are the record breaking performances in 1984 of three of our major generating stations. Included were Merrimack Station, which generated 10.6% more kilowatt-hours in 1984 than in 1983; Newington Station, which was available 88% of the time as opposed to the national average of 75.8%; and Schiller Station, where two units posted 94% and 99% availability records.

Everyone at PSNH has worked diligently during 1984 to overcome the difficult challenges that were presented. The immediate crisis we faced in the spring of 1984 has passed, but securing the long-term viability of the Company remains ahead. In the coming year, management, employees and the Board of Directors of your company are committed to continue to work toward the successful completion of a number of goals that are vital to assuring that long-term viability.

Among the most important of these goals are, first, the completion of the current, proposed financing, which is designed to provide funds for the Company's share of the cash cost to complete Seabrook Unit 1; and second, the completion of that unit in the most expeditious manner.

Over the past year, as we have faced the challenges presented to us and have made the difficult decisions, the interests of the Company's shareowners, as well as those of its customers and employees, have been ever present in our minds. This will, I assure you, continue to be the case.

To conserve cash, we have elected once again this year to forego the more traditional Annual Report to Shareowners. In its place we are providing to each shareowner a copy of the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 15, 1985.

Sincerely,

RJ Harrison

Robert J. Harrison
President and
Chief Executive Officer

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended	Commission File Number
December 31, 1984	1-6392

Public Service Company of New Hampshire

(Exact name of registrant as specified in charter)

NEW HAMPSHIRE	02-0181050
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

1000 ELM STREET, MANCHESTER, NEW HAMPSHIRE	03105
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant's telephone number, including area code: **603-669-4000**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $5 Par Value	New York Stock Exchange
Preferred Stock, $25 Par Value, 11% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 11.24% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 17% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 15% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 15.44% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 13% Dividend Series	New York Stock Exchange
Sinking Fund Preferred Stock, $25 Par Value, 13.80% Dividend Series	New York Stock Exchange
General and Refunding Mortgage Bonds, Series B 12% due 1999	New York Stock Exchange
General and Refunding Mortgage Bonds, Series C 14½% due 2000	New York Stock Exchange
General and Refunding Mortgage Bonds, Series E 18% due 1989	New York Stock Exchange
15¾% Debentures due 1988	New York Stock Exchange
14⅜% Debentures due 1991	New York Stock Exchange
15% Debentures due 2003	New York Stock Exchange
17½% Debentures due 2004	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of Class

Preferred Stock, $100 Par Value, 3.35% Dividend Series
Preferred Stock, $100 Par Value, 4.50% Dividend Series
Convertible Preferred Stock, $100 Par Value, 5.50% Dividend Series
Preferred Stock, $100 Par Value, 7.92% Dividend Series
Sinking Fund Preferred Stock, $100 Par Value, 7.64% Dividend Series
Sinking Fund Preferred Stock, $100 Par Value, 9.00% Dividend Series

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 __ .

The aggregate market value of the shares of Common Stock, $5 par value of the Company held by non-affiliates of the Company was $176,557,923 on February 14, 1985.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the close of the period covered by this report.

Class	Outstanding at December 31, 1984
Common Stock, $5 Par Value	37,191,067 Shares

Documents Incorporated by Reference

Portions of the definitive proxy statement for the Company's 1985 Annual Meeting of Stockholders. (Part III)

PUB ICE COMPANY OF NEW HAMPSHIRE

FORM 10-K ANNUAL REPORT

Table of Contents

PART I

PART II

PART III

PART IV

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

1984 FORM 10-K ANNUAL REPORT

Table of Contents

PART I

PART II

PART III

PART IV

PART I

Item 1. BUSINESS

Introduction

Public Service Company of New Hampshire (the "Company") is the largest electric utility in New Hampshire, operating a single integrated system which supplies electricity to approximately three quarters of the State's population. It distributes and sells electricity at retail in approximately 200 cities and towns, including Manchester, Nashua, Portsmouth, Berlin, Keene, Laconia and Rochester, in the State of New Hampshire. It also sells electricity at wholesale to seven other utilities. See *Wholesale Customers* below. The Company was incorporated in 1926 under the laws of the State of New Hampshire.

The Company is the principal owner of the Seabrook nuclear generating plant, Unit 1 of which is currently under construction and which has experienced persistent and substantial cost increases. The principal risks associated with the completion of construction of Seabrook Unit 1 are that the costs of completing the Unit will increase inordinately, the Company will be unable to finance its share of such costs or one or more of the other Seabrook Joint Owners will be unable or unwilling to finance or pay its share of such costs, or one or more regulatory agencies will decide that the Unit should not be completed. If construction of Unit 1 were not completed, or commercial operation were unduly delayed, or adequate rate relief were not granted the Company upon commencement of commercial operation, it would be very difficult for the Company to avoid proceedings under the Bankruptcy Code.

The area served by the Company experienced relatively rapid population and economic growth during the 1970's and continues to experience one of the lowest unemployment rates in the nation. After several years of relatively flat kilowatt-hour sales, the Company experienced an increase of 6.1% in prime sales for 1984 and 3.6% in 1983. These increases in kilowatt-hour sales reflect, among other things, an increase in the number of customers served and a general improvement in economic conditions. At December 31, 1984 the Company served approximately 314,300 customers, an increase of 4.1% compared to December 31, 1983.

Industry Problems

Electric utilities throughout the United States which are constructing nuclear generating plants have been the subject of extensive adverse publicity and criticism. Some nuclear projects have been discovered to have unanticipated construction defects and quality assurance deficiencies which have led to substantial cost overruns and significant construction delays, resulting in some cases in project abandonments. Several electric utilities have announced licensing problems with and cancellations of unfinished nuclear plants, which have resulted in substantial write-offs and the reduction or omission of dividends. In the case of one utility, delay in obtaining an operating license from the Nuclear Regulatory Commission ("NRC") as a result of, among other things, difficulties in completing emergency response and evacuation plans has threatened the utility's solvency. In addition, various state authorities are reviewing alternatives for the moderation of the effect on rates of placing major generating facilities in service upon commencement of commercial operation by, for example, phasing the cost of such facilities into rate base over a period of years rather than recognizing the full cost immediately. Various state authorities have proposed and instituted cost containment plans under which the costs for construction projects above a predetermined level are not fully reflected in rates. All of these events have adversely affected the market for the securities of utilities with nuclear investments, including the Company, and all of these problems may continue to affect the Company in the future. The insolvency of another electric utility with a nuclear investment might have a materially adverse effect upon the Company's financing plans.

For a further discussion of certain of these problems as they affect the Company, see *Seabrook Nuclear Plant*, Item 2, *Properties*, and Item 3, *Legal Proceedings* below.

Seabrook Nuclear Plant

The Company is the principal owner of a nuclear-fueled steam electric generating plant under construction at a site located in Seabrook, New Hampshire (the "Seabrook Plant"), which was planned to have two Westinghouse pressurized water reactors (each with a rated capacity of 1,150 megawatts), utilizing ocean water for condenser cooling purposes. Various other New England utilities are participating in the ownership of the Seabrook Plant under a Joint Ownership Agreement. The ownership interests in the Seabrook Plant are as follows:

Public Service C[illegible]ny of New Hampshire	35.56942%
The United Ill[illegible]ing Company	17.50000
Massachusetts [illegible]cipal Wholesale Electric Company	11.59340
New England [illegible]er Company	9.95766
Central Maine Power Company	6.04178
The Connecticut Light and Power Company	4.05985
Canal Electric Company	3.52317
Montaup Electric Company	2.89989
Bangor Hydro-Electric Company	2.17391
New Hampshire Electric Cooperative, Inc.	2.17391
Central Vermont Public Service Corporation	1.59096
Maine Public Service Company	1.46056
Fitchburg Gas and Electric Light Company	0.86519
Vermont Electric Generation and Transmission Cooperative, Inc.	0.41259
Taunton Municipal Lighting Plant	0.10034
Hudson Light and Power Department	0.07737
	100.00000%

After the decision by the Company on April 18, 1984 to suspend payment of its share of the construction costs of the Seabrook Plant (see *Financing — Liquidity Crisis* below), the Joint Owners entered into a number of agreements, including amendments to the Joint Ownership Agreement, to provide for the establishment of, among other things, a six-member Executive Committee, of which the Company is a member, to oversee the budget for the Seabrook Plant. The Executive Committee is in turn subject to the control of Joint Owners holding 51% of the ownership interests. As a result of these amendments, the Company no longer has sole authority over the level of construction expenditures at the Seabrook Plant. These arrangements also contemplate that the Company will delegate its responsibilities under the Joint Ownership Agreement for the construction and operation of the Seabrook Plant to a new managing agent.

New Hampshire Yankee. On June 23, 1984, at the same time that the Joint Owners adopted resolutions to resume construction of Seabrook Unit 1 and accepted the financing plans of the Seabrook participants for completion of construction of Seabrook Unit 1 (see *Financing — Newbrook Plan* below), the Joint Owners unanimously adopted a resolution providing for the phased transfer of construction and operation responsibilities from the Company to an independent entity, subject to the receipt of all necessary regulatory approvals, including particularly that of the NRC. See *Seabrook Unit 1 — Licensing* below. Responsibility for construction of Unit 1 is presently vested in a new division of the Company, known as the New Hampshire Yankee Division. On January 31, 1985, the Company was notified by the staff of the NRC that the organization of, and the delegation of responsibilities by the Company to, the New Hampshire Yankee Division were acceptable. Effective upon receipt of all required regulatory approvals, the New Hampshire Yankee Division will be reconstituted as an independent corporate entity, to be known as New Hampshire Yankee Electric Corporation ("N.H. Yankee"), which will assume the Company's responsibilities for the completion of construction and start up of Unit 1. The Joint Owners of the Seabrook Plant will own the new corporation and will be represented on its governing board in proportion to their ownership of the Seabrook Plant. The existing agreement between the Company, as agent for the Joint Owners, and Yankee Atomic Electric Company ("YAEC") for the provision by YAEC of engineering, quality assurance, and other services for Seabrook Unit 1 will then be administered by N.H. Yankee. It is contemplated that at some future time, subject to regulatory approval, N.H. Yankee may be given responsibility for the operation and maintenance of Unit 1.

A petition has been filed by an intervenor with the Director of Nuclear Reactor Regulation of the NRC seeking an immediate halt of construction of the Seabrook Plant, alleging that the transfer by the Company of its construction and operation responsibilities has already taken place in violation of the construction permits for the Plant. The Company cannot predict the resolution of this petition.

Throughout the period of construction and operation of Unit 1 the Joint Owners' Executive Committee will continue to review and approve or modify construction budgets, costs of construction, and the costs of operation and maintenance of Unit 1 as well as the disbursement of Joint Owner payments made under the Joint Ownership Agreement.

Construction. The Seabrook Plant has experienced persistent and substantial cost increases. The increased costs have been due, among other reasons, to design changes, revisions of regulations of and other actions by the NRC and other regulatory bodies, extraordinarily high interest rates, inflation and construction delays, all of which have resulted in total costs, including allowance for funds used during construction ("AFUDC") (see Note 2 of Notes to Financial Statements), far higher than planned. Allegations have been made in derivative lawsuits against certain officers and directors of the Company, one of which also names United Engineers & Constructors, Inc., the architect/engineer for the Seabrook Plant ("UE&C"), that mismanagement of construction of the Plant has resulted in schedule delays and increased costs of the Plant. See Item 3, *Legal Proceedings — Other* below. The estimates of cost and completion dates for the Seabrook Plant released in March 1984 were about 75% greater and 18 months later, respectively, than those made by UE&C in November 1982, which were in turn 43% greater and 10 months later, respectively, than previous estimates. Expenditures on Seabrook Unit 2 were reduced to a minimal level in the spring of 1984, and there is no viable plan for completing Unit 2 at this time. See *Seabrook Unit 2* below.

On March 1, 1984 the Company hired a new construction manager for the Seabrook Plant who had been responsible for the successful construction and commencement of commercial operation of a nuclear generating plant in the southeastern United States in a total of about six years. Since the arrival of this manager, a number of contractors employed to work on the Plant have been eliminated and an improved construction management system has been installed. The agreement of the relevant construction trade unions to apply the Nuclear Power Construction Stabilization Agreement to the Seabrook Plant has also been obtained; the Agreement contains work rule changes which the Company believes are advantageous as well as a no-strike clause.

Seabrook Unit 1. Construction of Unit 1 was suspended by the Company in April 1984, and resumed on July 2 at an expenditure level averaging $4 million per week. An August 30, 1984 update of the estimate of the cost and schedule completed by the Company's New Hampshire Yankee Division, estimated that the Unit would cost $4.5 billion (including AFUDC at a composite rate for all Joint Owners) and that the Unit would commence commercial operation on August 31, 1986. This update to the estimate reflected the effects of the shutdown of construction from April to July 1984, an assumed limitation on cash construction expenditures to an average of $4 million per week during the balance of 1984 and the elimination of expenditure limitations thereafter. In the fall of 1984 an independent consulting firm retained by the Joint Owners reviewed the August 30, 1984 updated estimate of cost and schedule of Unit 1 which assumed the resumption of full construction in January 1985, and concluded that, based on that assumption, the estimate of the cash cost to complete Unit 1 had a good probability of being achieved but that the probability of achieving full power commercial operation by August 31, 1986 was very low. By action of the Joint Owners the expenditure level was increased to $5 million per week commencing December 1, 1984. The Company believes that this expenditure limit will remain in effect until regulatory authorities have issued orders permitting the completion of Seabrook Unit 1. See *Other Seabrook Participants* and Item 3, *Other New Hampshire Proceedings.* The earliest date this could occur is April 1, 1985. The estimates used in this Report are based on the assumption that the expenditure limit will be removed by that date and that Seabrook Plant construction management will be able to plan in advance for removal of the limit so as to ensure optimum construction scheduling. However, it is now unlikely that the expenditure limit will be completely removed by that date.

At December 31, 1984, Unit 1 of the Seabrook Plant was estimated to be approximately 83% complete. The principal concerns of the Company with respect to Unit 1 are its cost, commercial operation date, licensing, rate treatment and regulatory approvals for completion of construction. Adverse developments with respect to any of these concerns could jeopardize the completion of Unit 1. If construction of Unit 1 were not completed, or commercial operation were unduly delayed, or adequate rate relief were not granted the Company upon commencement of commercial operation, it would be very difficult for the Company to avoid proceeding under the Bankruptcy Code.

Cost. At December 31, 1984, the Company had invested in Unit 1 and common facilities approximately $1,193,700,000 (including AFUDC of $395,900,000 but excluding uranium fuel of $80,700,000). If expenditure limitations currently in effect were lifted effective April 1, 1985, the commercial operation date would be October 31, 1986, and the total cost of Unit 1 would be $4.6 billion including AFUDC at a composite rate for all Joint Owners of $1.7 billion and a management contingency allowance of $170 million, but excluding uranium fuel. The Company's share of this cost would be $1,809,700,000 (including AFUDC of $759,200,000 but excluding uranium fuel of $98,000,000). The Company anticipates that after the expenditure limit has been removed, revised estimates for Seabrook Unit 1 will be made.

Commercial Operation Date. The principal factor affecting the cost of Unit 1 at this time is its commercial operation date. Substantial revisions to all prior estimates of such date have been made from time to time. The current estimate of the commercial operation date of Unit 1 is October 31, 1986, assuming the expenditure limit is completely removed by April 1, 1985. Various later commercial operation dates for Unit 1 have been estimated by other participants, construction consultants, regulatory bodies and other parties.

Licensing. Timely receipt from the NRC of an operating license is necessary in order to commence commercial operation of Unit 1. Formal hearings were held in the summer of 1983 and further hearings are expected to be held in 1985. The Company's request for the operating license is being actively opposed by intervenors, including the Attorneys General of the State of New Hampshire and the Commonwealth of Massachusetts. In the course of the proceedings for the issuance of the operating license, it is anticipated that the New Hampshire Civil Defense Agency, the Massachusetts Civil Defense Agency and the Federal Emergency Management Agency will develop emergency response and evacuation plans in conjunction with 17 municipalities in New Hampshire and 7 municipalities in Massachusetts in proximity to the Plant. Most of the responsible governmental entities appear to be proceeding with the development of emergency response and evacuation plans, although several Massachusetts and New Hampshire municipalities and the Massachusetts Attorney General are opposing such development or the adequacy of the proposed procedures and plans. The Company cannot predict whether such opposition, or that of other intervenors, might delay the commercial operation of the Unit, and the Governor of Massachusetts has indicated that he will not certify the Massachusetts plan to the Federal Emergency Management Agency unless all affected Massachusetts municipalities have approved their respective plans. State and local opposition has delayed licensing of another nuclear generating plant located on Long Island, New York for such an extended period that the inability of the constructing utility to earn a cash return on its investment in the plant has threatened that utility's solvency.

The NRC Advisory Committee on Reactor Safeguards reviewed the application for a Seabrook operating license, toured the site and, in April 1983, issued its letter recommending favorably upon low-power operation of the Seabrook Units.

During the suspension of construction the Company reviewed documentation for the remaining construction and assessed the status of construction to date. At this point in the construction of Unit 1, no serious deficiencies have been found in the quality assurance program, which is a comprehensive program for verification of engineering, construction, testing and vendor compliance with design requirements, NRC regulations and code requirements. However, there can be no assurance that such deficiencies will not be found. See *Industry Problems*.

Various intervenors have attempted to assert a contention challenging the financial qualifications of the Company and certain other Joint Owners in light of the February 7, 1984 decision of the United States Court of Appeals for the District of Columbia Circuit in *New England Coalition on Nuclear Pollution v. NRC* (No. 82-1581). That decision remanded to the NRC a regulation promulgated in 1982 which eliminated a prior requirement for demonstrating that an electric utility applicant possessed reasonable assurance of obtaining funds to cover estimated operation costs and costs of permanently shutting the facility down. On June 7, 1984, the NRC issued a Statement of Policy directing NRC licensing boards to treat the remanded regulation as valid insofar as it applied to operating license proceedings pending the outcome of a then pending rulemaking proceeding before the NRC. On August 16, 1984, the NRC adopted a final rule obviating the need to demonstrate financial qualifications in connection with the issuance of an operating license. An appeal of the promulgation of this rule by the NRC has recently been filed in the United States Court of Appeals for the District of Columbia Circuit. The Company cannot predict what effect the eventual resolution of this matter will have on the licensing proceedings.

Rate Treatment. The timing and extent of recovery by the Company of the cost of the Seabrook Plant from ratepayers has become a major political issue in New Hampshire. Under a so-called anti-CWIP statute enacted into New Hampshire law in 1979 prohibiting the reflection in rates of construction work in progress, Unit 1 of the Seabrook Plant may not be reflected in rates until completion of its construction and commencement of commercial operation. The Company cannot predict what rate increases will be granted, but anticipates that the costs of Unit 1 will be phased into rates on some basis. The Company is also unable to predict what effect any such rate increases would have on the demand for electricity. On July 23, 1984 the Company announced that it would seek to recover through rates no more than its actual share of a $4.5 billion aggregate cost of construction of Unit 1, contingent upon (1) the occurrence of no catastrophic developments clearly outside the control of construction management and (2) the timely receipt of regulatory approvals by the Joint Owners for financing the construction completion costs and for the change in management structure. See *Other Seabrook Participants* for the current status of regulatory approvals. The Company believes that its acceptance of a limit on the total cost of the Unit for ratemaking purposes should increase the feasibility of phasing Unit 1 into rates over a period of years on an acceptable basis.

A phase-in of Unit 1 could result in the deferral by the Company of very large amounts of revenue which would have been collected had the entire cost of Unit 1 been placed into rates immediately. This deferral, and the Company's external financing requirements, increase substantially if the phase-in is prolonged or the cost of the Unit increases. The Company's financing plan described under *Financing — Five-Year Program* below assumes that its share of such cost of Seabrook Unit 1 will be reflected in rates on a phased-in basis after the Unit begins commercial operation, currently estimated to be in October 1986. The Company believes that based on these assumptions Unit 1 could be phased into rates over a number of years, with annual increases of about 10% plus a yearly inflation adjustment of about 5%. The ultimate recovery of deferred revenues that would result from a phase-in would require that the Company obtain rate increases each year for a number of years beyond the 1985-1989 period discussed below under *Financing — Five Year Program*. The Company cannot predict whether cumulative rate increases of a size required to recover the Company's investment in the Unit will be granted by the New Hampshire Public Utilities Commission ("NHPUC").

The amount of the costs of constructing Unit 1 includible in the Company's rate base upon completion of Unit 1 is expected to be the subject of controversy in the NHPUC proceeding considering the matter. Allegations have been made that construction of Unit 1 has been mismanaged and that such mismanagement has resulted in excessively high costs. See Item 3. *Other*. Only costs found by the NHPUC to have been prudently incurred would be included in the Company's rate base; future earnings would be adversely affected to the extent that the full costs of Unit 1 were not reflected in rates.

The Company's cash flow will improve as Seabrook Unit 1 is reflected in rates. Delay in commercial operation of Unit 1 or in the reflection in rates of a substantial portion of the costs of the Unit would require the Company to obtain significant amounts of external financing. See *Financing* below. There can be no assurance that the Company would be able to obtain such financing. Even after inclusion of Unit 1 in rate base, any outage of the Unit of such a nature or duration as to result in its removal from rate base would impose significant burdens on the Company because Unit 1 and common facilities will constitute more than half of the Company's total assets and will be the source of a significant portion of its electric generating capacity.

Regulatory Approvals for Completion of Construction. All of the approvals and permits from various state and federal regulatory bodies required for completion of construction of the Seabrook Plant have been obtained and, except as described below and except for the regulatory proceedings related to financings described below under *Other Seabrook Participants* and under Item 3, *Other New Hampshire Proceedings*, there are no appeals or proceedings related thereto currently being actively prosecuted. However, continued opposition at the regulatory level and through court appeals is likely. The process of obtaining these approvals and permits has been long and complex, has been consistently opposed by a number of intervening groups, has witnessed demonstrations at the Seabrook Plant site, and has been plagued by lengthy delays which have resulted in greatly increased costs for the Seabrook Plant.

An addition to the 345 KV transmission grid in Massachusetts is needed in connection with the operation of the Seabrook Plant. The addition has been approved by Massachusetts regulatory authorities, but there are court appeals opposing it, and additional regulatory and court proceedings are pending.

In connection with the implementation of the N.H. Yankee arrangements for construction and operation of the Seabrook Plant described above under *Seabrook Nuclear Plant — New Hampshire Yankee*, it will be necessary to obtain the approval of the NRC and various state regulatory bodies. On October 12, 1984, the NHPUC issued an order authorizing N.H. Yankee to engage in business as a public utility for the purpose of acting as management agent for the construction of the Seabrook Plant. The Company anticipates that intervenor groups which have consistently opposed the construction and licensing of the Seabrook Plant will actively oppose the granting of such approvals, particularly before the NRC. The Company cannot predict the impact which such opposition may have on the timing or outcome of the proceedings in which such approvals are sought.

Other Seabrook Participants. Other Seabrook Joint Owners subject to the jurisdiction of regulatory authorities in Connecticut, Maine, Vermont and Massachusetts have been or are presently involved in proceedings in each state regarding the Seabrook Plant. The Company cannot predict the outcome of these proceedings.

In November 1984, the Connecticut Department of Public Utility Control determined that the construction of Seabrook Unit 1 is economically viable at the then current estimates of cost and schedule and that the Connecticut Joint Owners (which hold an aggregate of 21.5% of the ownership interests) should continue their participation in Seabrook Unit 1. In late December 1984, the Department declined to reconsider its decision. In the case of The United Illuminating Company, regulatory approval of a portion of its financing plan is contingent upon removal of expenditure limitations on the construction of Unit 1 by May 5, 1985.

On December 28, 1984 the Vermont Public Service Board (the "VPSB") rendered a 2-1 decision approving the continued participation of the Vermont utilities (which hold an aggregate of 2.0% of the ownership interests) in Seabrook Unit 1 on the condition that the financing of all Joint Owners for the cash completion cost of the Unit be in place by April 15, 1985. The VPSB decided that the cash cost to complete the Unit was less than the cost of other power sources, assuming a Unit 1 commercial operation date as late as August 1987 and a cost to complete of between $1 billion and $1.3 billion. The VPSB scheduled a hearing for April 16, 1985 to review the status of the financing plans of all Joint Owners and various other matters relating to Unit 1.

On January 15, 1985, the VPSB denied a motion for reconsideration of its December 28, 1984 order. The VPSB reaffirmed its earlier decision that "under the most optimistic of circumstances [Seabrook Unit 1] is marginally economic, and, if [Seabrook Unit 1] cannot be securely prefinanced by mid-April, 1985, then it should be cancelled." The VPSB stated that, if Unit 1 is not completely prefinanced and the funds for that purpose are not isolated from the potential bankruptcy of the Company by April 15, 1985, Unit 1 will not be completed in a timely and economic manner and it is therefore better for Vermont ratepayers that Unit 1 be cancelled.

On December 13, 1984, the Maine Public Utilities Commission ("MPUC") ordered the three Maine utilities (which hold an aggregate of 9.7% of the ownership interests) to obtain "credible, firm offers" to buy their interests in Unit 1 by January 11, 1985. By that date, offers to buy about one-third of the combined ownership interests were received, although at prices lower than anticipated by the MPUC. The Maine utilities have appealed the December 13 order to the Maine Supreme Court. In addition, the Maine utilities have filed briefs with the MPUC which question the authority of the MPUC to order disengagement from the Seabrook Project.

Pursuant to the MPUC's order of January 16, 1985, which directed the Maine utilities to file by February 8, 1985 plans for "disengaging" from the Seabrook Project, the Maine utilities submitted on that date their analyses of disengagement alternatives and a further report of sales efforts with respect to their interests in Unit 1. The January 16, 1985 order also provided that comments on the disengagement alternatives could be filed by February 22, 1985 and that the MPUC would at an indefinite future date issue another order on disengagement. The Maine utilities have affirmed their intention to continue to meet their contractual obligations under the Joint Ownership Agreement in the absence of an unstayed legally binding order of the MPUC requiring the utilities not to make their payments.

The Massachusetts Department of Public Utilities, at the request of certain of the Massachusetts utilities which are Joint Owners of the Seabrook Plant (which hold an aggregate of 26.0% of the ownership interests), is investigating three issues common of all of the utilities: the estimated cost of completing Seabrook Unit 1; the estimated completion date of the Unit; and the cost of the electricity to be generated by the Unit. An order in this proceeding is expected by March 31, 1985, and the facts established in this proceeding will be used in the separate proceedings on each of the Massachusetts' utilities proposed plans to finance their share of the cost to complete Unit 1. Orders approving the Massachusetts Joint Owners' financings may not be received until the end of April 1985.

If, due to regulatory action, financial difficulties or any other reason, one or more of the other Seabrook Plant participants should be unable or unwilling to fulfill their contractual commitments to pay on a timely basis their share of Unit 1 construction costs, completion of Unit 1 would be jeopardized. If Unit 1 were not completed, it would be very difficult for the Company to avoid proceedings under the Bankruptcy Code.

Insurance. The Federal Price-Anderson Act provides, among other things, that the maximum liability for damages resulting from a nuclear incident would be the greater of the maximum amount of financial protection required by the NRC to be carried by licensees or $585,000,000. As required by NRC regulations, prior to operation of the Seabrook Plant, the owners of the Seabrook Plant will insure against this risk by purchasing the maximum available private insurance (presently $160,000,000), the balance to be covered by retrospective premium insurance and by an indemnity agreement with the NRC. Under amendments to the Price-Anderson Act, owners of operating nuclear facilities may be assessed a retrospective premium of up to $5,000,000 for each reactor owned in the event of any one nuclear incident occurring at any reactor in the United States, with a maximum assessment of $10,000,000 per year per reactor owned. As a part owner of other operating New England nuclear facilities (see *Joint Projects* below), the Company would be obligated to pay its proportionate share of any such assessments, which presently amounts to a maximum of $1,050,000 per incident. While no final evaluation of the claims being asserted as a result of the incident at Three Mile Island is yet possible, the Company does not anticipate any assessments being levied under these provisions as a result of that incident.

Seabrook Unit 2. Expenditures on Seabrook Unit 2 have been reduced to a minimal level. There is no viable plan for the completion of construction of Unit 2 at this time, and the Company does not have current estimates of the Unit's cost or commercial operation date.

Under the Joint Ownership Agreement, cancellation of Unit 2 can only be effected by the vote of at least 80% of the ownership interests, so that cancellation requires the Company's concurrence in such a vote. However, the Joint Ownership Agreement requires the vote of at least 51% of the ownership interests to resume construction of Unit 2, and resumption of construction by the present Joint Owners is extremely unlikely.

In June 1984 the New Hampshire Supreme Court ruled that the New Hampshire anti-CWIP statute prohibits recovery from ratepayers of any of the Company's investment in the cancelled Pilgrim Unit 2 generating plant located in Massachusetts. The Company has a 3.47% interest in that plant (an investment of approximately $16 million), which was cancelled by the lead owner in 1981, and the Company had filed a petition with the NHPUC in December 1983 seeking recovery of its investment. The Supreme Court expressly did not reach the question of whether the statute, as so interpreted, was constitutional, or whether the Company could receive a higher rate of return based on additional risk to investors represented by the inability to recover investments in cancelled plants due to the anti-CWIP statute. If allowed to do so, the Company intends to establish the requisite factual record in proceedings before the NHPUC and then seek a final determination by the Court of the constitutional issues. The Company believes that a final judicial determination of the recoverability of its Pilgrim Unit 2 investment will not be made before the end of 1985.

However, even if the constitutional issues were to be resolved favorably, the Company cannot predict what action the NHPUC would take regarding either the Company's Pilgrim Unit 2 investment or the Company's Seabrook Unit 2 investment if Seabrook Unit 2 is cancelled. If the NHPUC denied recovery and subsequent administrative and judicial appeals, if any, were unsuccessful, the Company would be required to charge the unrecovered cost of the units against earnings when such denial become final. The amount charged against earnings could substantially reduce the Company's retained earnings; the precise amount would depend upon a number of factors, including, in the case of Seabrook Unit 2, the possible allocation of some costs to Seabrook Unit 1, the amount of cancellation charges resulting from negotiations in connection with contract terminations and salvage. The Company estimates that the amount of the after-tax charge against earnings made in the case of Seabrook Unit 2 could approximate its present investment in Seabrook Unit 2 ($301,900,000 at December 31, 1984).

Effective March 1, 1984, the Company ceased capitalization of all costs, including AFUDC, related to Seabrook Unit 2. The effect of this decision was to reduce 1984 net income by approximately $35,200,000.

Construction Program

The Company's aggregate construction program for the five-year period 1985-1989, which will be subject to continuing review and adjustment throughout the period, is currently estimated to be about $616,100,000 (excluding AFUDC). The following table sets forth the Company's estimated construction expenditures for the period 1985-1989, and is based on current construction schedules and cost projections (excluding AFUDC of approximately $435,700,000):

	Estimated Construction Expenditures 1985-1989 (Millions of Dollars)	
Generating Facilities	1985	1986-1989
Company's Share of Seabrook Unit 1		
Plant	$180.8	$114.1
Nuclear Fuel	11.4	43.1
Total	192.2	157.2
Other Generation	31.6	67.1
Total Generating Facilities	223.8	224.3
Transmission Facilities	2.2	33.4
Distribution and General Facilities	23.3	109.1
Total	$249.3	$366.8

The aggregate amount of the Company's estimated construction program for each of the years 1985-1989 is as follows:

1985	$249,300,000
1986	157,100,000
1987	68,800,000
1988	69,000,000
1989	71,900,000
Total	$616,100,000

Actual construction expenditures have substantially exceeded past estimates and could exceed these estimates. See *Seabrook Nuclear Plant* above. It is also possible that additional expenditures may be required to meet regulatory and environmental requirements at the Seabrook Plant and the Company's other generating facilities.

Financing

Liquidity Crisis. Following announcement of the substantial increase in the estimated cost of the Seabrook Plant on March 1, 1984, the Company's commercial banks indicated that they were unwilling to make advances under their $160,000,000 Revolving Credit Agreement with the Company (under which no amounts were outstanding) unless the Company obtained back-up sources of credit. Because funds were no longer available to the Company under the Revolving Credit Agreement, it was necessary for the Company to commence strict cash conservation measures which included a vote by the Board of Directors on April 19, 1984 to omit the quarterly dividends payable on May 15, 1984 on shares of Common and Preferred Stocks and suspension on April 18, 1984 of payment of the

Company's share of Seabrook Plant construction costs. The Company reduced non-Seabrook construction, began a program of reducing the number of non-Seabrook employees and reduced the salaries of executive officers and certain other salaried employees. The Company ceased the oil-to-coal conversion of three 50 MW units at its Schiller Station, which had been scheduled to be completed by the end of 1984. The payment of principal in the amount of $5,000,000 was not made when due under the Company's Acceptance and Stand-By Revolving Credit Facility Agreement with certain banks. Consequently, the banks terminated their commitments to provide further loans under this Agreement. As a result of the foregoing nonpayment, the commercial banks terminated their commitment to make loans under the Revolving Credit Agreement. The Company did not pay when due the May 1, 1984 installment on its Nuclear Material Lease and Security Agreement with PruLease, Inc. under which a borrowing of $50,000,000 was outstanding secured by a lien on the Company's interest in nuclear fuel for the Seabrook Plant. In consequence, PruLease, Inc. terminated the Agreement and demanded payment of all outstanding unpaid rents, the outstanding principal of all borrowings and all additional losses, damages and expenses associated with the Company's actions. The foregoing payment defaults were cured on June 20, 1984 when the Company sold $90,000,000 principal amount of its Secured Exchangeable Promissory Notes 20% due 1985 and applied a portion of the proceeds toward the payment of outstanding debts.

The Company also deferred paying half of a New Hampshire franchise tax payment in the amount of approximately $2,000,000 for 30 days and deferred other payments, including payments to contractors for the Seabrook Plant and for the Schiller Station coal conversion and payments to its coal supplier.

On August 24, 1984, the Company signed agreements with its existing lenders which restructured the Company's indebtedness held by banks and its agreement with PruLease, Inc. This restructuring extended the maturity of an aggregate of $75 million of bank debt maturing in 1984 to May 31, 1985. In addition, the Company obtained the agreement of UE&C to the extension of approximately $20.5 million of credit to the Company; this amount is due on May 31, 1985 and is subject to the same conditions and rights of acceleration as the bank debt and PruLease, Inc. financing. Extension of the maturity of any of these financings is dependent upon extension of the others on terms satisfactory to each lender.

On August 24, 1984, the Company also signed an agreement providing until May 31, 1985, a $35 million revolving credit facility secured by the Company's accounts receivable. This facility has the same conditions as the other agreements described above and numerous additional conditions to the making of any loans under the facility. These conditions are such that, as a result of the completion of the financing in December 1984, the Company cannot make use of this facility.

The foregoing agreements contain prohibitions on additional indebtedness, negative pledge clauses and covenants by the Company not to redeem or purchase any shares of its capital stock (including the making of sinking fund payments on any series of its Preferred Stocks) unless the Company has retired all of its loans from the financing institutions and terminated the revolving credit facility. The effect of this latter restriction is to prevent the Company from paying dividends on shares of Common Stock until the financing institutions' debt is repaid, since, under the Company's Articles of Agreement, no dividends on shares of Common Stock may be paid so long as any arrearage exists in respect of dividends on, or sinking fund payments in respect of any series of, the Company's Preferred Stocks. The Company's agreement with certain of its lenders contains further restrictions on the payment of dividends. In its order approving the December 1984 financing, the NHPUC imposed a condition that the Company not pay preferred and common dividends until authorized to do so by further NHPUC order. As a result of the Company's omission since April 1984 of quarterly dividends payable on shares of its Preferred Stocks, the holders of shares of the Preferred Stocks have the right to elect a majority of the Board of Directors of the Company. See Note 8 of Notes to Financial Statements.

The restructured agreements with the Company's lenders contain provisions to the effect that payment of the debt may be demanded immediately if the financing described under *Newbrook Plan* below is not consummated by February 28, 1985, current estimates of the cost and completion date of Seabrook Unit 1 exceed earlier estimates, or certain minimum spending levels for construction at Seabrook Unit 1 are not achieved by February 28, 1985. The Company is in the process of seeking amendments of these and certain other provisions of these agreements and waivers of certain defaults. It is likely that further amendments will be needed by the end of March 1985. The Company is also negotiating the extension of the May 31, 1985 maturity date of these agreements, other than the secured revolving credit facility, which the Company proposes to terminate.

In December 1984 the Company issued $425,000,000 of debentures and warrants to purchase common stock. In addition to converting $90,000,000 of short-term notes to long-term debt, the financing provided cash proceeds of approximately $275,000,000, which the Company estimates will provide for its working capital needs until the estimated completion date of Seabrook Unit 1.

Newbrook Plan. As part of a plan to complete the construction of Unit 1 of the Seabrook Plant each Seabrook Joint Owner submitted to the other Joint Owners (i) a plan for raising funds sufficient to pay for such Joint Owner's share of the remaining cost to complete Unit 1 and (ii) a schedule for regulatory approvals of such plan. The plans assume a cash cost to complete construction of Unit 1 of $1.0 billion and a commercial operation date in October 1987. Each of such plans and schedules was approved by the Joint Owners. In order to obtain such approval each Joint Owner had to evidence that the required financing would be available by satisfying one of the following criteria:

(1) the Joint Owner has debt securities rated A– or better by both Moody's Investors Service, Inc. and Standard & Poor's Corporation; or

(2) the Joint Owner has a commitment from the Rural Electrification Administration to guarantee loans which will fund that owner's share of the cost to complete Unit 1; or

(3) the Joint Owner provides an irrevocable letter of credit from a financial institution (the long-term debt of which is rated A or better by both Moody's Investors Service, Inc. and Standard & Poor's Corporation) sufficient to fund that owner's share of the cost to complete Unit 1 when that owner cannot otherwise obtain funds; or

(4) the Joint Owner agrees to put into an escrow account an amount of cash which, together with interest thereon, would be sufficient to pay its share of the cost to complete Unit 1.

To fulfill its commitment under this Newbrook Plan, the Company intends to issue in the second quarter of 1985 up to $525 million principal amount of debt securities, designed to yield proceeds to the Company of $340 million. These securities will likely be of two types: deferred interest, third mortgage bonds issued directly to the public ("DIBS") and third mortgage bonds issued to secure pollution control revenue bonds to be issued by the New Hampshire Industrial Development Authority on behalf of the Company. It is contemplated that the DIBS will not require interest payments for a period of up to two years and will be issued at a discount from their principal amount. The discount is designed to approximate compound interest on the amount paid by the purchasers of the bonds for the period during which interest is not paid. Thereafter interest would accrue and be payable semi-annually. All of these bonds would be secured by a third mortgage on substantially all of the Company's property located in New Hampshire. The proceeds received by the Company after underwriting discounts and expenses will enable the Company to deposit into the escrow account funds sufficient to pay its share of the remaining estimated construction costs of Seabrook Unit 1.

The issuance of these securities is currently the subject of protracted hearings before the NHPUC. See Item 3, *Other New Hampshire Proceedings — NHPUC Approvals of Financings and Appeals*. The Company expects an order in this proceeding by March 31, 1985. However, due to an uncertainty in New Hampshire law, the Company may not be able to issue such securities until all appeals of the NHPUC order have been decided by the New Hampshire Supreme Court. Such a decision may not be rendered for two months or more after the NHPUC order has been issued. Certain other regulatory bodies have imposed deadlines (see *Seabrook Nuclear Plant — Other Seabrook Participants* above) that require that all Joint Owners complete their financing for Unit 1 by April 15, 1985 or that require removal of the expenditure limit on the construction of Unit 1 by May 5, 1985. If the securities are not issued by April 15, 1985 or the construction limit is not lifted by May 5, 1985, certain other Joint Owners may have to return to their commissions for further hearings or new proceedings, the result of which cannot be predicted. In the event of a negative ruling by the NHPUC regarding the issuance of these securities or the inability of the Joint Owners to complete their financings, Seabrook Unit 1 may not be completed and it will be difficult for the Company to avoid proceedings under the Bankruptcy Code.

Five-Year Program. The Company's external financing requirements for the period 1985-1989 total approximately $683 million. Through a financing completed in December 1984, the Company has provided for its estimated working capital needs until the estimated completion date of Seabrook Unit 1. The majority of the external financing is needed for funding construction expenditures of $616.1 million and refinancing of debt maturities and payment of sinking fund requirements of $410.0 million. It is anticipated that the balance of funds required will be generated internally in the years 1988 and 1989. As discussed above, the Company is seeking authorization from the NHPUC to raise at least $340.0 million for expenditures associated with the construction of Seabrook Unit 1. These external financing requirements assume that (a) the rate increase associated with Seabrook Unit 1 will be 10% per year commencing in late 1986 (and in addition that the Company's rates are increased 5% per year to reflect inflation), (b) the Company's lenders extend the maturity of $125 million of indebtedness maturing on May 31, 1985 to 1989, but the remaining $20.5 million maturing on May 31, 1985 will not be extended beyond 1987, (c) the cost to complete Seabrook Unit 1 does not exceed $882 million, and (d) approximately $100 million of the funds raised by the Company for the prefunding of its share of the cost to complete the Unit will be returned to the Company in late 1986.

The Company expects that to meet its estimated capital requirements for the period 1985-1989 the external financings set forth in the table below will be necessary:

1985	$340,000,000
1986	—
1987	80,500,000
1988	140,500,000
1989	122,000,000
Total	$683,000,000

The external financing requirements set forth above assume no payment of any Preferred Stock dividends before the first quarter of 1987. If the Company were to pay such dividends before the first quarter of 1987, additional external financing would be required.

Achieving the financing program outlined above depends upon external financing in the securities markets, since the Company is unable to obtain any significant amount of additional short-term bank credit, and also depends on many other factors, some of which are not within the Company's control. As a result of the Company's omission of dividends on its Common and Preferred Stocks, the Company does not believe it could presently sell any additional shares of its Preferred or Common Stocks on reasonable terms. Consequently, at least until the Company has paid all arrearages in dividends on shares of its Preferred Stocks, the Company is required to obtain all of its external financing requirements through the issuance of debt instruments in the securities markets.

Mortgage Bonds. Due to certain restrictions in the Company's First Mortgage Indenture, no significant amount of First Mortgage Bonds may be issued thereunder until an operating license is obtained for Unit 1 of the Seabrook Plant.

Because of these restrictions in the Company's First Mortgage Indenture, the Company entered into the General and Refunding Mortgage Indenture dated as of August 15, 1978 (the "G&R Indenture"), constituting a second mortgage on the Company's properties to secure General and Refunding Mortgage Bonds (the "G&R Bonds"), pursuant to which the Company has issued and sold an aggregate of $223,000,000 of G&R Bonds, of which $212,080,000 is outstanding. This amount does not include $17,563,000 aggregate principal amount of G&R Bonds, Series G Variable Rate due 1987 (the "Series G Bonds") issued and pledged as collateral under the Company's nuclear fuel financing agreement with PruLease, Inc. described above under *Financing — Liquidity Crisis*. The G&R Indenture requires that, in order to issue additional G&R Bonds, the earnings coverage of interest on the First Mortgage Bonds and G&R Bonds be at least 2.0. At December 31, 1984, the earnings coverage test permitted the issuance of $179,000,000 principal amount of additional G&R Bonds (20% annual interest rate assumed).

Debentures. The Company has outstanding $700,000,000 principal amount of debentures. The debentures are unsecured long-term obligations of the Company and do not require the Company to maintain any asset ratio or cash reserves. Under limitations contained in the Company's Articles of Agreement, the Company could issue at December 31, 1984 approximately $48,000,000 of long-term unsecured indebtedness and $235,000,000 of long or short-term unsecured indebtedness. The general effect of the provisions in the Articles of Agreement is to limit the cumulative amount of unsecured term indebtedness incurred during a stated period to an aggregate amount of secured and unsecured indebtedness (other than indebtedness issued for refundings) not exceeding 60% of net plant additions (subject to adjustments) during the period. In addition the Company can issue long or short-term unsecured indebtedness not in excess of 20% of the total of secured indebtedness and capital and surplus.

Preferred Stock. Under the Company's Articles of Agreement, additional shares of Preferred Stock may be issued without the affirmative vote of the holders of a majority of the outstanding shares of either class of the Preferred Stock provided that the ratio of earnings to fixed charges and preferred dividends, including dividends on shares of Preferred Stock to be issued, is at least 1.50. At December 31, 1984, the Company could issue, without such vote of the holders of shares of Preferred Stock, approximately $202,000,000 of Preferred Stock (17% annual dividend rate assumed). However, in view of the omission of dividends on the Company's Preferred Stock (see *Financing — Liquidity Crisis* above and Note 8 of Notes to Financial Statements) and the failure to make sinking fund payments on certain series of the Company's Sinking Fund Preferred Stocks, the Company does not believe that it will be able to sell any additional shares of its Preferred Stocks on reasonable terms until all dividend arrearages have been paid. The Company's restructured agreements with its lenders and orders of the NHPUC contain restrictions on the payment of dividends on shares of Common and Preferred Stocks and on the making of sinking fund payments.

New England Power Pool

A New England Power Pool ("NEPOOL") Agreement, to which the major investor-owned utilities in New England, including the Company, and certain municipal and cooperative utilities are parties, has been in effect since 1971. The NEPOOL Agreement provides for joint planning and operation of generating and transmission facilities and also incorporates generating capacity reserve obligations and provisions regarding the use of major transmission lines and payment for such use.

Substantially all planning, operation and dispatching of electric generating capacity for New England is done on a regional basis under the NEPOOL Agreement. At the time of the 1984-1985 NEPOOL winter peak, the New England utilities had about 21,745 MW of installed capacity and purchases to meet the New England peak load of about 16,854 MW.

The Company's capability responsibility under the NEPOOL Agreement involves carrying an allocated share of a New England capacity requirement which is determined for each period based on certain regional reliability criteria. Assuming the completion of Seabrook Unit 1, it is expected that the Company's capacity will be sufficient, through its own generating facilities, through its participation in certain jointly-owned generating facilities, and through purchases of capacity and energy from other utilities, to meet its NEPOOL Agreement obligations at least until the 1990's.

Canadian Power. NEPOOL, on behalf of its members including the Company, has entered into an Interconnection Agreement with Hydro-Quebec, a Canadian utility operating in the Province of Quebec, which provides for construction of an interconnection between the electrical systems of New England and Quebec. Those parties have also entered into an Energy Contract and an Energy Banking Agreement; the former obligates Hydro-Quebec to offer NEPOOL participants up to 33 million MWH of surplus energy during an eleven-year term commencing September 1, 1986, and the latter provides for energy transfers between the two systems. NEPOOL has negotiated an additional purchase from Hydro-Quebec of 7 million MWH per year for a ten-year period starting in 1990. Work is proceeding on licensing and permitting for this purchase.

In 1984 Hydro-Quebec and the Vermont Department of Public Service signed a contract for the sale by Hydro-Quebec to Vermont for a ten-year period beginning September 1, 1985 of 150 MW of firm power.

Joint Projects

The Company is a part owner with other New England electric utilities of four nuclear generating companies. The Company owns a 7% interest in Yankee Atomic Electric Company, a 5% interest in Connecticut Yankee Atomic Power Company, a 5% interest in Maine Yankee Atomic Power Company and a 4% interest in Vermont Yankee Nuclear Power Corporation, each of which owns an operating nuclear generating plant with present net capabilities of 176 MW, 582 MW, 846 MW and 528 MW, respectively. The stockholders of each of the four nuclear generating companies are entitled to the entire output of the plant in proportion to their respective ownerships, subject to certain sales agreements with other utilities, and are obligated to pay for such output their proportionate shares of the generating company's operating expenses and returns on invested capital. They are also obligated to pay, when called upon by the individual generating company, their proportionate shares of such generating company's capital requirements not provided from outside financing.

The Company is participating on a tenancy-in-common basis with other New England utilities in the ownership of two nuclear generating units under construction (assuming no further construction expenditures by the Company for Seabrook Unit 2):

				Company Share			
						Estimated Construction Cost(2)(4)	
	Type	Scheduled Completion Date(1)(2)	Capacity MW	Percent(2)	Capacity MW(2)(3)	Total (Millions)	Per KW
Seabrook Unit 1 (New Hampshire)	Nuclear	10/86	1,150	35.56942	409.05	$1,907.7	$4,664
Millstone Unit 3 (Connecticut)	Nuclear	5/86	1,150	2.8475	32.7	$ 127.3	$3,893

(1) These completion dates have been deferred from time to time in the past, and additional deferrals may occur due to licensing and regulatory delays, the financial condition of joint owners of the units, economic conditions and other factors.

Due to the time required for the construction of generating facilities and the completion of licensing and regulatory proceedings relating thereto, substantial investments in the above units have been and will be required prior to the completion of licensing and regulatory proceedings. There is no assurance that all necessary approvals, permits or licenses will be obtained or, if obtained, will not be modified or revoked.

(2) See *Seabrook Nuclear Plant* and *Construction Program* above and Item 3, *Other New Hampshire Proceedings* below. The total cost and cost per KW of the Company's ownership interest in Unit 3 of the Millstone Plant has been calculated based upon the most recent estimate of cost and commercial operation made by the principal owner in September 1984.

(3) Pursuant to arrangements with two Seabrook participants, the Company is obligated to purchase from such participants, if so requested, up to a total of 75 megawatts of capacity and related energy from Unit 1 for the first three years of commercial operation and 54 megawatts of capacity and related energy from Unit 1 for the next seven years.

(4) Including the cost of the initial nuclear fuel and AFUDC on the estimated costs of unfinished construction.

Fuel Supply

For the year ended December 31, 1984, the Company's firm net output was derived 44.8% from oil, 39.4% from coal, 9.0% from nuclear, 6.4% from hydro and 0.4% from other sources.

Oil. The New England electric utilities, including the Company, make greater use of fuel oil for generation of power than utilities in any other region of the country. Most fuel oil supplies of the New England utilities are derived from foreign sources and subject to price fluctuations and interference by foreign governments. Fuel oil for the Company's oil burning Newington and Schiller Stations is supplied by a contract with one supplier which expires on January 31, 1986 and by spot oil purchase. The fuel storage capacity for these plants is approximately 30 days operating at full load, and inventory varies substantially depending upon oil shipments. During the 52-week period ending December 31, 1984, the average inventory was approximately 12 days operating at full load.

Coal. Coal for the Company's Merrimack Station is presently being furnished from West Virginia sources under a contract which expires in March, 1988. The contract generally provides that a 60-90 day supply of coal is to be maintained for the Company, that the base price of the coal may be changed by the seller annually but that the Company's disagreement with the change will result in termination of the contract at the end of the contract year, and that the price of the coal is subject to certain adjustments for changes in the seller's costs. The Company's policy is to have a 60-90 day supply of coal maintained for the Merrimack Station depending on time of year and potential mine labor work stoppages. On December 31, 1984, a 97-day supply was on hand. Merrimack Station presently requires approximately 1,000,000 tons of coal per year.

Two units of the Company's Schiller Station are in the process of being converted to burn coal with conversion of a third unit having been completed in 1984. Coal for Schiller Station is presently being furnished from Virginia sources under a contract which expires in November 1988. The contract generally provides that an adequate supply is maintained for the Company, that the base price of the coal may change annually up or down and that other price components of the coal are subject to certain adjustments for changes in the seller's costs. The coal inventory requirements for the Schiller units are in the process of being determined. On December 31, 1984, a 68-day supply of coal for the single unit already converted was on hand. Schiller Station, when all three units have been converted from oil to coal, will require approximately 400,000 tons of coal per year.

The Company's Merrimack and Schiller coal units will require a total of approximately 1,400,000 tons of coal per year in 1986 and beyond. See *Conversion from Oil to Coal* below.

The Company's approximate average costs of oil and coal for 1980 through 1984 were as follows:

	Oil Per Barrel	Oil Per Million BTU	Coal Per Ton	Coal Per Million BTU
1980	$22.86	$3.67	$43.57	$1.60
1981	30.58	4.92	47.14	1.71
1982	26.49	4.24	51.79	1.89
1983	26.55	4.52	53.17	1.99
1984	28.22	4.40	54.77	2.04

Nuclear. The nuclear fuel cycle consists of (1) the mining and milling of uranium ore into uranium concentrates, (2) the conversion of uranium concentrates to uranium hexafluoride, (3) the enrichment of uranium hexafluoride, (4) the fabrication of nuclear fuel assemblies and (5) the reprocessing, storage, or disposal of spent nuclear fuel.

The Joint Owners of the Seabrook Plant have contracted for the nuclear fuel cycle materials and services required to commence operation of Unit 1 and to meet Unit 1's requirements through 1990. Contracts for segments of the nuclear fuel cycle beyond 1990 will be required, and their availability, prices and terms cannot be predicted.

As required by the Nuclear Waste Policy Act of 1982, the Seabrook Joint Owners plan to enter into a contract with the United States Department of Energy ("DOE"), prior to operation of the Seabrook Plant, for the transport and disposal of Seabrook spent fuel at a national nuclear waste repository. Under the Act a national repository for nuclear waste is anticipated to be in operation by 1998; however, because of contingencies in the Act, the Company cannot predict whether the federal government will be able to provide interim storage or permanent disposal repositories for spent fuel and/or high level radioactive waste materials. The Seabrook Plant will have enough on-site storage to accommodate all spent fuel accumulated through the year 2000.

The Company has been advised by the companies operating or constructing the other nuclear generating stations in which the Company has an interest that they have contracted for certain segments of the nuclear fuel cycle through various dates. The Company has further been advised that these four operating nuclear generating stations have or will have storage capacity to meet the spent fuel storage needs of the units through various dates ranging from 1990 to the late 1990s.

Conversion from Oil to Coal

In October, 1982, the NHPUC adopted a settlement agreement designed to afford the Company a method of accelerated recovery of the capital costs associated with the conversion of the three Schiller Units from oil to coal burning (initially ordered by the NHPUC in March 1980) and to provide incentives or penalties (as the case may be) depending upon the completion dates of such conversion (originally scheduled to be completed by December 31, 1984). The Company suspended work on the conversion in April, 1984, as part of the Company's stringent cash conservation measures. On June 1, 1984, the NHPUC opened an investigation into the circumstances surrounding the suspension of the conversion activities. The Company recommenced the conversion activities effective July 2, 1984. It is now estimated that the conversion will cost approximately $62 million, of which approximately $50 million had been incurred as of December 31, 1984, and will be completed by mid-1985. The penalty provisions of the settlement agreement referred to above may, depending upon the decision of the NHPUC following conclusion of the investigation, become operative but the Company cannot now determine the amount of any penalties which may be assessed.

Regulation

The Company, as to retail rates, securities issues, and various other matters, is subject to the regulatory authority of the NHPUC. The Connecticut Department of Public Utility Control has limited jurisdiction over the Company based on the Company's ownership as a tenant-in-common of a portion of Millstone Unit 3. See *Joint Projects* above. Based upon the Company's ownership of generating and transmission facilities in Vermont and Maine, the Company is subject to limited regulatory jurisdiction in those states. The Company is also subject, as to some phases of its business, including accounts, certain rates, and licensing of its hydroelectric generating plants, to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") under the Federal Power Act. The various nuclear generating units in which the Company has an ownership interest are subject in their construction and operation to the broad regulatory jurisdiction of the NRC under the Atomic Energy Act of 1954, particularly in regard to public health, safety, environmental and antitrust matters. See also *Environmental Matters* below.

National Energy Policy

The Federal Public Utility Regulatory Policies Act of 1978 ("PURPA") requires state utility regulatory commissions to make determinations with respect to certain issues of utility regulation. The NHPUC has accepted the recommendations of parties to a consultative process to adopt the PURPA Section 111 rate-making standards and the additional rate-making objectives of rate continuity, revenue stability and practicality of rates in principle and to the design of the lifeline rate for residential customers ordered by the NHPUC. Implementation of certain of the PURPA rate-making standards has begun in accordance with the results of the consultative process. Further decisions with respect to implementation were made in the Company's most recent retail rate case including the approval of a settlement agreement regarding rate structure, conservation and load management. Lifeline rate issues were also addressed in the proceeding. The NHPUC has also accepted the Company's proposed special industrial contract policy, with certain reservations, and a pilot targeted lifeline program. See Item 3, *New Hampshire — Retail Rate Proceedings*.

The NHPUC initiated a proceeding to revise existing short-term rates and to establish long-term avoided cost rates to be paid for energy sold to the Company by small power producers and cogenerators, and has approved a settlement agreement entered into by the parties to the proceeding.

Environmental Matters

The Company is subject to regulation with regard to air and water quality and other environmental considerations, by various federal, state and local authorities. The Company cannot forecast the effect of all such regulations upon its generating, transmission and other facilities, or its operations.

The application of federal, state and local standards to protect the environment, including but not limited to those hereinafter described, involves or may involve review, certification or issuance of permits by various federal, state and local authorities. Such standards, particularly in regard to emissions into the air and water, thermal mixing zones and water temperature variations, may halt, limit or prevent operations, or prevent or substantially increase the cost of construction and operation of generating plants and may require substantial investments in new equipment at existing generating plants. They may also require substantial investments which are not included in the estimated construction expenditures set forth under *Construction Program* above.

Air Quality Control. Pursuant to the Federal Clean Air Act of 1970, as amended, the State of New Hampshire acting through the New Hampshire Air Resources Agency ("ARA") has adopted regulations containing standards limiting emissions of particulates, sulphur oxides and nitrogen oxides, which are generally designed to achieve and maintain federal primary ambient air quality standards. The Company believes that its fossil fuel generating units are being operated in compliance with ARA's regulations, with the exception of Unit 1 at the Company's Merrimack Station.

Pursuant to the 1977 amendments to the Clean Air Act, ARA has proposed lists showing those areas of New Hampshire which have attained or failed to attain national ambient air quality standards, and revised the State implementation plan, which the Environmental Protection Agency ("EPA") has accepted. It does not appear that the revised State implementation plan will require the Company either to modify operations at any of its fossil fuel generating plants or to expend funds for additional air pollution control equipment.

While coal now available and expected to be available in the future for the Company's Merrimack and Schiller Stations presently meets all applicable requirements, if more stringent requirements become effective which could not be met by such coal, the Company might have to install sulfur removal equipment at substantial capital cost or take such other actions as may be required by regulatory authorities. The installation of such equipment would increase operating costs and reduce the net capability of the units.

The new permits for the two units at the Company's Merrimack Station issued in early 1984 placed more stringent limits on the opacity of the smokestack discha. ,e. In November 1984 particulate emissions tests were conducted on Unit 1 at the Merrima^k Station following reports submitted to the ARA by the Company that indicated the opacity limits established in the new permits were being exceeded for that Unit. Unit 2 continues to meet the limits so established. Based upon a showing in the test report that actual emissions exceeded the allowable emission rate prescribed by New Hampshire air quality regulations, the ARA issued, on January 31, 1985, a Notice of Violation and Order of Abatement. The Order of Abatement directed the Company to install within 36 months new pollution control equipment on Unit 1 for the permanent reduction of particulate emissions and to implement the interim compliance schedule proposed by the Company in December 1984.

The conversion of Schiller Station from oil to coal discussed under *Conversion from Oil to Coal* above has required the Company to make expenditures for air quality control equipment which are reflected in the estimates set forth under *Construction Program*.

Water Quality Control. The Company has received from EPA, or from the Maine Department of Environmental Protection in the case of one generating station located in the State of Maine in which the Company has an ownership interest, all permits required under the Federal Water Pollution Control Act, as amended, for discharges of thermal and other effluents from its generating stations. Such permits have varying expiration dates and the Company has made and expects to make applications for renewal. The EPA issued effluent limitations guidelines for steam electric power plants based on application of the best practicable control technology (to be met by July 1, 1977) and of the best available technology economically achievable (to be met by July 1, 1984), and alternate effluent standards with respect to thermal discharges from steam electric power plants. The guidelines and standards impose rigorous limitations upon the industry. An industry group filed an appeal in a Federal Court of Appeals challenging the guidelines and standards, and the Court of Appeals remanded the guidelines and standards to the EPA for reconsideration of certain of them. The Company is in compliance with the July 1, 1977 guidelines and the best available technology economically achievable effluent limits specified in the Company's existing permits.

The Company has an ongoing requirement in the discharge permit for its Merrimack Station to monitor the effect of the plant's operation on the Merrimack River. The Company has thus far been able to show as required by the permit that the plant's present once-through cooling system does not interfere with resident fish in the affected portion of the Merrimack River. The permit requires that additional biological studies be performed by the Company at such times as significant numbers of migratory fish are restored to the Merrimack River for the purpose of showing as required by the permit that the present cooling system does not interfere with migratory fish.

The Company's construction and operation of the Seabrook Plant, including environmental considerations, is subject to regulation by the NRC and the EPA. See *Seabrook Nuclear Plant* above.

Resource Conservation and Recovery Ac:. Pursuant to the Resource Conservation and Recovery Act of 1976, the EPA has issued regulations relative to the generation, transportation and disposal of certain wastes. In addition, the New Hampshire Bureau of Hazardous Waste Management has similar regulations which have received final approval from the EPA. The Company has reviewed the application of these regulations to its operations and has complied with the applicable EPA and New Hampshire Bureau of Hazardous Waste Management regulations.

Other Environmental Expenditures. At December 31, 1984, the Company's share of expenditures for environmental protection facilities at the Seabrook Plant amounted to approximately $109,500,000, the major portion of which was for facilities to reduce the thermal effect of the discharge of the Seabrook Plant condenser cooling system.

Employees, Salaries and Wages

The Company has approximately 2,200 employees, of whom 525 are employed by the New Hampshire Yankee Division and will become employees of New Hampshire Yankee when the required regulatory approvals are received. Five hundred forty of the Company's employees (none of whom are employed by the New Hampshire Yankee Division) are represented by unions with which the Company has contracts expiring on May 31, 1985. These contracts provided for salary increases of 5.0% for the first year of the contract and an additional 5.0% effective June 1, 1984. Salary increases are granted from time to time on a comparable basis to nonrepresented employees.

Municipalities and Cooperatives

New Hampshire law permits municipalities to engage in the production and sale of electricity, and to condemn the plant and property of any existing public utility which is located in the municipality. Municipalities may finance the ownership of new generating units of at least 25 MW and new transmission facilities of at least 69 KV through the issuance of municipal electric revenue bonds. Municipalities may also finance the ownership of generating units utilizing renewable resources of not greater than 80 MW and related equipment and structures through the issuance of municipal small scale power facility bonds.

The New Hampshire Electric Cooperative, Inc. ("NHEC"), a cooperative association financed by the Rural Electrification Administration, as well as five small municipal electric utilities, operate in areas adjacent to areas served by the Company. NHEC, which has a 2.17391% ownership interest in the Seabrook Plant, currently purchases, as a wholesale customer, most of its electricity from the Company and is subject to regulation by the NHPUC as a public utility.

Wholesale Customers

The Company sells power at wholesale to seven municipal and investor-owned electric utilities. On September 7, 1984, two of the Company's wholesale customers, Exeter & Hampton Electric Company and Concord Electric Company, notified the Company that they intend to terminate their existing power purchase contracts with the Company effective September 30, 1986. These terminations may require regulatory approvals. These customers have stated that they intend to negotiate power purchase contracts with a number of suppliers, including the Company. Such contracts may be subject to regulatory approvals. For the year ended December 31, 1984, the power sold to these two utilities accounted for approximately 12% of the Company's total power sales. The revenues derived from such sales accounted for approximately 8% of the Company's total revenues from electric sales for the same period.

On December 11, 1984 the Company filed a petition for a declaratory order with the FERC requesting that the contract terminations be delayed until November 1993. This filing was accepted and assigned a docket number. On January 14, 1985 these customers filed a petition to intervene in that docket and presented a motion to dismiss. The Company answered that motion on January 29, 1985. The FERC has taken no action in the docket to date.

Due to the extended period of time in which the terminations would take effect, the various alternatives that could be ordered by FERC or negotiated by the Company with these customers, and the potential for sale of the power to other wholesale customers should terminations occur, the Company is unable to predict what effect termination of these contracts would have on its financial condition.

For the year ended December 31, 1984, sales of power to the Company's other wholesale customers accounted for approximately 7% of the Company's total power sales and 5% of the Company's total revenues from electric sales; almost all of these sales are to NHEC. Because of planned purchases of additional power capacity by NHEC, the amount of power purchased by NHEC from the Company and the revenues derived therefrom is not expected to increase and may decrease in the future. The anticipated capital requirements shown in *Financing — Five Year Program* above reflect the Company's estimate of the effect of these power capacity purchases by NHEC.

Seasonal Nature of Business

Although the number of kilowatt-hours of electricity sold by the Company in its territory has historically been somewhat less in the summer and fall than during the winter and spring, the Company's electric revenues and operating income are dependent on a variety of other factors which are not necessarily seasonal, including contract sales of system and unit power to other electric companies, changes in the Company's rates and charges, the extent and nature of transactions involving NEPOOL and general economic conditions.

Item 2. PROPERTIES

The electric properties of the Company form a single integrated system including transmission facilities which are part of the New England-wide transmission grid. The Company has 1,183 MW of its own generating capacity, 98 MW from its participations in the four nuclear generating companies described under Item 1, *Joint Projects* and various contracts for purchased capacity. On January 21, 1985, the Company experienced its maximum one-hour prime peak load of 1,307 net MW. The generation and transmission systems of the major New England utilities, including the Company, are operated as if they were a single system. See Item 1, *New England Power Pool*.

The Company has a two-unit coal-fired 465 MW electric generating station (Merrimack Station), from one unit of which the Company has agreed to sell to another utility 100 MW on a single unit basis through April 1998, one oil-fired 428 MW electric generating station (Newington Station) and the Schiller Station (183 MW). Two units of the Schiller Station are currently being converted from oil to coal. Conversion of a third unit has been completed, and the unit went into commercial operation on December 22, 1984. Conversion work on the remaining two units is expected to be completed by mid-1985. See Item 1, *Conversion from Oil to Coal* and *Environmental Matters* with respect to Schiller Station. The Company also has other generating units with an aggregate effective capability of 203 MW as follows: hydro-electric (65.5 MW), combustion turbine (115 MW), diesel (3 MW) and its share (19.5 MW) of Wyman Unit 4, a 620 MW oil-fired generating plant jointly-owned with other utilities and located in the State of Maine.

The Company is also participating with other New England utilities in the design and construction of two additional nuclear-fueled generating plants, Seabrook Unit 1 and Millstone Unit 3. See Item 1, *Seabrook Nuclear Plant* and *Joint Projects*.

On December 31, 1984, the Company had about 1,721 pole-miles of transmission lines, 9,779 pole-miles of distribution lines, and 228 transmission and distribution substations having an aggregate capacity of 5,468,807 KVA.

The Company owns office buildings in Manchester, Portsmouth and Keene. It rents space in an office building in Manchester for its principal offices under a 30-year lease expiring in 2002. Annual base rentals under this lease are approximately $1,330,000 subject to annual escalation. In 1984 the Company paid approximately $2,074,000. The Company also owns other structures used as service buildings, storehouses and garages and leases space for offices and other purposes at various locations in its service area.

Substantially all of the properties of the Company are subject to the lien of its First Mortgage Indenture and G&R Indenture and the Company has granted a lien on the Company's interest in nuclear fuel for the Seabrook Plant to PruLease, Inc. See Item 1, *Financing*. The principal properties of the Company are held by it in fee and are free from other encumbrances, subject to minor exceptions, which do not substantially impair the usefulness to the Company of such properties. The transmission and distribution facilities of the Company are with minor exceptions either located on land owned in fee or pursuant to easements, or with respect to those in or over public highways or public waters are so located pursuant to adequate statutory or regulatory authority, subject to minor defects, which do not, however, threaten to impair the right of the Company to maintain and operate its poles, wires and conduits.

Item 3. LEGAL PROCEEDINGS

New Hampshire — Retail Rate Proceedings

On January 30, 1984, the NHPUC in a 2-to-1 decision authorized a $24,700,000 permanent annual increase in the Company's retail rates (which amounts to 74% of the $33,400,000 increase originally requested). Because rates had been collected under bond at the $33,400,000 level since August 1, 1983, the Company refunded approximately $5,000,000 in February 1984 representing the difference between the amounts collected under the bonded rates and the amount that would have been collected had the permanent rates then been in effect.

The NHPUC allowed the Company a 16.1% return on common equity. While the Company's requested attrition allowance of 1.25% was not accepted, the decision provided for a step adjustment in revenues, as of July 1, 1984, for certain rate base additions and increased expenses. On June 11, 1984, the Company notified the NHPUC that it would not file for the step adjustment.

The majority decision stated that the NHPUC was entitled to review the Company's management of construction at the Seabrook Plant and that, should the circumstances warrant, a proceeding would be opened to investigate the management of the Seabrook construction program. In a dissenting opinion, one commissioner stated that she would lower the allowed return on common equity to 14.54% (which would reduce the rate increase to $19,500,000) to reflect a judgment that management of the Company has been deficient in that, among other things, it failed to develop more current and definitive cost and schedule estimates than those contained in the November 1982 estimates developed by United Engineers & Constructors, Inc., the Seabrook Plant's architect/engineer. See Item 1, *Seabrook Nuclear Plant — Construction.*

Other New Hampshire Proceedings

While the NHPUC instituted a proceeding in late 1983 to explore whether an agreement could be negotiated as to the cost and completion date for Unit 1, with incentives and penalties for variations from agreed upon cost, the question of the amount of the construction costs which the Company would seek to recover through rates is also being considered in the current NHPUC proceeding regarding the financing of the costs to complete Unit 1. See *NHPUC Approvals of Financings and Appeals* below. See also Item 1, *Seabrook Nuclear Plant — Seabrook Unit 1 — Rate Treatment* above as to the Company's position with respect to the amount of construction costs of Unit 1 which it would seek to recover through rates.

The Company's request for recovery through its rates of its share of the cancelled Pilgrim Unit 2 nuclear plant is currently pending before the NHPUC. In June 1984, the New Hampshire Supreme Court held that a New Hampshire statute prohibits recovery from ratepayers of any of the Company's Pilgrim Unit 2 investment. The Court did not decide whether the statute, as so interpreted, is constitutional. If allowed to do so, the Company intends to establish the requisite factual record in proceedings before the NHPUC and then seek a final determination by the Court of the constitutional issues. The Company believes that a final judicial determination of the recoverability of its Pilgrim Unit 2 investment will not be made before the end of 1985.

The Company continues to supply data in response to data requests of the NHPUC Audit Staff in conjunction with the NHPUC audit of the construction costs for the Seabrook Plant initiated in September 1983 for the purposes of verification that the reported costs of the Plant are includible and appropriate as part of the Company's rate base and that proper compliance with the applicable NHPUC accounting rules and regulations has in the past been and will hereafter be achieved. The Company has received initial reports of certain preliminary exceptions resulting from the NHPUC audit, which the Company does not believe are significant.

On April 29, 1983, the NHPUC issued Report and Sixteenth Supplemental Order No. 16,374 in its Docket DE 81-312 Investigation into the Supply and Demand for Electricity. In this Report and Order, the NHPUC concluded, among other things, that the most likely completion dates for Seabrook Unit 1 and Seabrook Unit 2 were March 1986 and March 1990, respectively, and that a cost estimate of at least $8 billion for the Seabrook Plant was probable based on the NHPUC's findings as to completion dates. The NHPUC has since indicated that it would open investigatory dockets to consider: (i) methods to reduce or spread out the impact of the "rate shock" due to the pending inclusion of Seabrook Unit 1 in rate base; and (ii) long-term conservation and load management programs. The Company presently cannot predict when these investigations will be commenced or what effect their outcome will have on the Company.

On May 1, 1984, a formal petition was filed with the NHPUC requesting the NHPUC to institute a proceeding to investigate the level of rates being charged by the Company and, after such investigation, to disallow recovery of any portion of the Company's current rates related to the Seabrook Plant found to be unwarranted by the Company's conduct of the Seabrook Plant construction program. The petition has been dismissed by the NHPUC. Another petition was filed with the NHPUC in June 1984 by the same petitioner, seeking substantially the same relief. In addition, in June 1984, the Consumer Advocate of the NHPUC filed a petition seeking disallowance in current rates of any costs associated with the Seabrook Plant, as well as other rate reductions.

In June 1984, the NHPUC concluded investigations into the adequacy of the Company's coal inventory for its Merrimack Station and the oil inventory for its Schiller and Newington Stations, finding in each case that the Company should maintain inventories at prescribed levels. An additional investigation into the suspension of the Schiller Station Coal Conversion Project has not been completed. See Item 1, *Fuel Supply* and *Conversion from Oil to Coal*.

NHPUC Approvals of Financings and Appeals. By orders dated June 1, 1984 and June 18, 1984, the NHPUC authorized the issuance of $90,000,000 of Secured Exchangeable Promissory Notes, which were sold to institutional investors on June 20, 1984. At the hearing on the Company's petition to the NHPUC with respect to the issuance of these Notes, the Chairman of the NHPUC denied two motions to intervene. The would-be intervenors appealed to the New Hampshire Supreme Court the NHPUC's denial of their motions for reconsideration, and one of the would-be intervenors also appealed to the New Hampshire Supreme Court the NHPUC's denial of its motion for reconsideration of the June 1, 1984 order. The Court heard arguments on these appeals on January 8, 1985, but has not yet rendered a decision.

On September 21 and September 26, 1984, the NHPUC issued orders approving the Company's petition to issue up to an aggregate of $425 million principal amount of units and debentures, which were sold in December 1984. The orders, issued by a two-to-one vote, imposed five conditions on the approval. Three of these conditions are as follows:

(1) the Company must file a monthly statement with the NHPUC showing the disposition of the proceeds from the sale of the units and debentures;

(2) the Company may not spend at a level in excess of its share (35.56942%) of $5 million per week on Seabrook construction until authorized to do so by NHPUC order; and

(3) the Company may not declare or pay preferred and common stock dividends until authorized to do so by further NHPUC order (see Item 1, *Financing — Preferred Stock* for a description of other restrictions on the Company's ability to pay preferred stock dividends, and see Item 5, *Market for the Company's Common Equity and Related Security Holder Matters* for other restrictions on the Company's ability to pay common stock dividends).

The Company has complied with the foregoing conditions.

The NHPUC also stated that two other conditions would be imposed. First, the Company could "service Seabrook related debt and accrue Seabrook related AFUDC at current levels until an order is issued" in the NHPUC proceeding which is considering whether to approve the Company's plan to raise its share of the cost to complete Seabrook Unit 1, and second, that the Company could not service such debt from the proceeds of these financings or accrue such AFUDC after the conclusion of that proceeding unless specifically authorized by the NHPUC to do so at that time. Until approval of the Company's plan to raise its share of the cost to complete Seabrook Unit 1, the Company will not use any of the proceeds from the $425 million financing to pay for its share of Seabrook construction costs or to service indebtedness which could be characterized as "Seabrook related debt".

On August 2, 1984, the NHPUC established a proceeding to investigate the Company's plan to raise its share of the cost to complete construction of Unit 1 of the Seabrook Plant. In this proceeding, the NHPUC intends to quantify the incremental cost of completing Unit 1 and to explore long-term alternatives to completion; the NHPUC also intends to evaluate the financial feasibility of the Company's financing, including a determination of the level of revenues necessary to support the capital structure of the Company resulting from completion. Certain of the intervenors in this proceeding have argued that cancellation of Unit 1 and the reorganization of the Company under the Bankruptcy Code is preferable for ratepayers to the increases in rates which would be required if Unit 1 is completed and reflected in rates. Hearings commenced on December 3, 1984. The Company does not expect the NHPUC to issue an order before March 31, 1985.

Other

Various class actions have been filed in the United States District Court for the District of New Hampshire against the Company and certain present and former officers and directors, Peat, Marwick, Mitchell & Co., the Company's independent certified public accountants (whose report on the Company's financial statements for the years ended December 31, 1984, 1983 and 1982 is included herein), underwriters of the Company's securities, and Ropes & Gray and Sulloway Hollis & Soden, outside counsel for the Company, alleging violations of the Securities Act of 1933, the Securities Exchange Act of 1934 and principles of common law: *Seidel* v. *Public Service Company of New Hampshire, et al.*, C-84-197D; *Stepak* v. *Public Service Company of New Hampshire, et al.*, C-84-205D; *Jacobs* v. *Public Service Company of New Hampshire, et al.*, C-84-250D; *Fendall* v. *Public Service Company of New Hampshire, et al.*, C-84-289D; *Lindenbaum* v. *Public Service Company of New Hampshire, et al.*, C-84-330D; *Cicci* v. *Public Service Company of New Hampshire, et al.*, C-84-358D; *Brawer* v. *Public Service Company of New Hampshire, et al.*, C-84-410D; *Seidel, et al.* v. *Public Service Company of New Hampshire et al.*, C-84-541D; and *Seidel* v. *Ropes & Gray and Sulloway Hollis & Soden*, C-85-79D. Each action is alleged to be brought on behalf of a class of purchasers of the Company's securities consisting of those who purchased through a particular public offering, through the Company's Dividend Reinvestment and Stock Purchase Plan or on the open market during various periods from October 29, 1981 through March 1, 1984. Unspecified damages and rescission are sought for alleged misrepresentations and omissions relating to the Seabrook Plant, including the estimated cost and completion date thereof, in the Company's prospectuses and other disclosure documents.

Various stockholder derivative actions, purportedly instituted on behalf of the Company, have been filed in the United States District Court for the District of New Hampshire, naming various present and former officers and directors of the Company and in two actions United Engineers & Constructors, Inc., the architect/engineer of the Seabrook Plant: *Markewich* v. *Tallman, et al.*, C-84-220D; *Zucker Associates, et al.* v. *Dorr, et al.*, C-84-206D; *Botos and Silver* v. *Tallman, et al.*, C-84-280D; and *Haber Crushed Fruit Co. Pension Trust* v. *Tallman, et al.*, C-84-383D. Such actions seek unspecified damages, an accounting by defendants, the rescission of contributions to the Company's benefit plans on behalf of and for the benefit of defendants, and injunctive relief with respect to continuation of construction and the issuance of securities or incurrence of debt to finance construction of the Seabrook Plant. Such actions allege various acts of waste and mismanagement and violations of defendants' fiduciary duties with respect to the construction and financing of the Seabrook Plant.

The foregoing lawsuits are all at a very early stage and answers to the complaints have not been required to be filed. The Company and the other defendants intend to contest these lawsuits vigorously.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There was no matter submitted to a vote of the Company's security holders during the fourth quarter of fiscal 1984.

Item 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

Information is set forth below as to the names and ages of the executive officers of the Company, their positions as officers of the Company both current and for the past five years, their length of service with the Company, and in the case of Messrs. Bayless, Cameron, Derrickson, Johnson and Thomas, a brief explanation of their respective prior five years' business positions and responsibilities.

Name	Position	Age and (Years of Service)
Robert J. Harrison	President and Chief Executive Officer since March, 1983; President and Chief Operating Officer (1981-1983); President and Chief Financial Officer (1980-1981); Financial Vice President (1978-1980)	53 (28)
John C. Duffett	Senior Vice President since December 1982, Vice President (1978-1982)	57 (31)
Charles E. Bayless	Financial Vice President since March, 1981; Director of Special Corporate Projects, Consumers Power Company, Jackson, Michigan (1978-1981)(2)	42 (4)
D. Pierre G. Cameron, Jr.	Vice President and General Counsel since September, 1980; Treasurer and Assistant Secretary, Baltimore Gas and Electric Company, Baltimore, Maryland (1979-1980); Associate General Counsel–Corporate, Baltimore Gas and Electric Company (1971-1979)(3)	50 (4)
William B. Derrickson	Senior Vice President — Nuclear Energy since March 1984; Director of Projects, Florida Power & Light Company, Miami, Florida (1982-1983); Project General Manager, Florida Power & Light Company (1977-1982)(4)	44 (1)
Henry J. Ellis	Senior Vice President since December, 1982; Vice President (1976-1982)	64 (38)
Roy G. Barbour	Vice President since December, 1982; Director–General Engineering Division (1981-1982); Director–System Planning (1977-1981)	57 (21)
George Branscombe	Vice President and Treasurer since January, 1985; Treasurer (1982-1985); Internal Audit Manager (1980-1982); Senior Auditor (1979-1980)	37 (5)
Raymond E. Closson	Vice President(1)	64 (38)
William T. Frain, Jr.	Vice President since December, 1982; Comptroller (1979-1982)	43 (20)
Warren A. Harvey	Vice President(1)	58 (37)
Wendell P. Johnson	Vice President since July, 1983; Vice President, Yankee Atomic Electric Company, Framingham, Massachusetts (1974-1983)(5)	62 (1)
James L. Nevins	Vice President(1)	50 (16)

Name	Position	Age and (Years of Service)
Robert A. Parks	Vice President since December, 1982; Director of Management Information Systems (1979-1982)	39 (16)
George S. Thomas	Vice President — Nuclear Production since May, 1982; Nuclear Production Superintendent (1980-1982); Manager, Startup Test Group, Yankee Atomic Electric Company, Framingham, Massachusetts (1978-1980) (6)	42 (4)
John J. Lampron	Assistant Vice President since December, 1982; Treasurer (1978-1982)	40 (13)
Robert G. Ouellette	Comptroller since December, 1982; Assistant Comptroller (1979-1982)	53 (33)
Russell A. Winslow	Secretary(1)	50 (23)

(1) Has held same position for at least 5 years.

(2) As Director of Special Corporate Projects for Consumers Power Company, Mr. Bayless was responsible for specialized financing projects, including nuclear fuel leases, leveraged and single investor leases, pollution control financing and acceptance facility agreements.

(3) As Treasurer and Assistant Secretary of Baltimore Gas and Electric Company, Mr. Cameron had supervisory responsibility for the Finance Department of Baltimore Gas and Electric Company, including all financial planning, cash management, stockholder records, insurance, employee benefit plan administration, and financial documents (statistical reports) activities. As Associate General Counsel–Corporate of Baltimore Gas and Electric Company, Mr. Cameron had both supervisory and primary responsibility for all legal aspects of equity and debt financings (including pollution control financings), proxy solicitation/annual meeting preparation, negotiation and preparation of major construction and equipment procurement contracts and federal government agency liaison.

(4) As Director of Projects for Florida Power & Light Company, Mr. Derrickson was responsible for all major power plant capital projects and project services, including cost and schedule control and estimating. Mr. Derrickson, in his position as Project General Manager for Unit 2 of the St. Lucie Plant of Florida Power & Light Company (an 800 megawatt pressurized water nuclear power plant) had the responsibility for the management of all phases of that project, which encompassed planning and scheduling, engineering, procurement of material, construction, licensing and startup.

(5) As Vice President of Yankee Atomic Electric Company, Mr. Johnson had overall responsibilities for project engineering, construction, project management and quality assurance. Mr. Johnson has also been in charge of the nuclear construction and quality assurance activities being performed by Yankee Atomic Electric Company for the Seabrook Plant.

(6) As Manager, Startup Test Group of Yankee Atomic Electric Company, Mr. Thomas was stationed at the Seabrook Plant with the responsibility for development of programs for all post construction testing activities, including startup testing. During 1978 and 1979 Mr. Thomas also participated in the startup activities at the North Anna Nuclear Power Station of Virginia Electric and Power Company, in activities associated with the Three Mile Island Recovery Operation and in the evaluation by the Electric Power Research Institute of the Three Mile Island incident.

PART II

Item 5. MARKET FOR THE COMPANY'S COMMON EQUITY AND RELATED SECURITY HOLDER MATTERS

The Company's shares of Common Stock are traded on the New York Stock Exchange, where the high and low sales prices during 1984 and 1983 were as follows:

	High	Low		High	Low
1984			1983		
First Quarter	12⅞	8	First Quarter	19¼	17½
Second Quarter	8½	3⅝	Second Quarter	20	16¾
Third Quarter	4⅞	3½	Third Quarter	17¾	16
Fourth Quarter	5	3⅝	Fourth Quarter	18⅛	10⅞

Since April 1984 the Company has omitted dividends on the Company's Common Stock as part of its cash conservation program described above under Item 1, *Financing — Liquidity Crisis*. Quarterly dividends of 53¢ per share were paid during 1983 and the first quarter of 1984.

Subject to the prior rights of shares of the Preferred Stock, $100 par value, and shares of Preferred Stock, $25 par value, to dividends and to the limitations set forth in this and the next succeeding paragraph, shares of Common Stock are entitled to dividends when and as declared by the Board of Directors out of any remaining funds legally available therefor. As a result of the omission since April 1984 of quarterly dividends payable on shares of the Company's Preferred Stocks, and the failure of the Company to make sinking fund payments on certain series of the Company's Sinking Fund Preferred Stocks, no dividends may be paid on shares of the Company's Common Stock. Such dividends may not be resumed until the Company has made the sinking fund payments and paid the dividend arrearage on shares of its Preferred Stocks. The revised financing arrangements with the Company's existing lenders prohibit the Company from redeeming or repurchasing any shares of its capital stock, including the making of sinking fund payments on its Sinking Fund Preferred Stocks, until the loans from such lenders have been repaid in full and their lending commitments terminated. In addition, in its September 1984 order approving the $425 million financing, the NHPUC imposed a condition that the Company not pay preferred and common dividends until authorized to do so by further NHPUC order.

The Articles of Agreement contain certain limitations, applicable so long as any shares of the Preferred Stock are outstanding, on the Company's right to declare dividends on shares of Common Stock out of net income (similar limitations are contained in certain indentures supplemental to the First Mortgage, applicable so long as any bonds of Series I through V are outstanding), or in the event Common Stock Equity (as defined) is less than 25% of Total Capitalization (as defined). Pursuant to terms of the Company's General and Refunding Mortgage Indenture, dividends may not be paid on shares of Common Stock in excess of the Company's Net Income accumulated after January 1, 1978 less the aggregate amount of all dividends paid or declared on shares of Preferred Stock of the Company during such period plus $32,000,000. At December 31, 1984, $230,282,000 of Retained Earnings was not subject to dividend restriction.

At December 31, 1984, there were 65,441 record owners of shares of the Company's Common Stock.

Dilution from the Exercise of Warrants. If exercised, the 18,375,000 warrants to purchase shares of common stock issued as part of the $425 million financing in December 1984 will increase the number of outstanding shares of Common Stock of the Company by 49%. The book value of the Company at December 31, 1984 per outstanding share was $24.61. The warrants will allow exercise at a price considerably below book value, diluting the book value of existing stockholders. On a pro forma basis, after giving effect to the assumed exercise of the warrants, book value at December 31, 1984 would be $18.12.

Funds received from the issuance and exercise of warrants are expected to be reflected in the Company's capital structure for rate-making purposes.

Item 6. SELECTED FINANCIAL DATA

	1984	1983	1982	1981	1980
	(Thousands except Per Share Amounts and Ratios)				
Operating Revenues	$ 525,585	$ 463,484	$ 423,290	$ 440,884	$ 351,247
Fuel and Purchased Power Expenses	258,316	234,971	224,830	255,247	187,248
Operating Income	87,244	68,150	43,469	47,051	47,307
Total AFUDC	144,033	137,347	97,672	78,619	71,729
Net Income	156,600	151,658	91,623	77,187	59,847
Earnings Per Common and Common Equivalent Share	3.07	3.49	2.73	2.65	2.77
Dividends Per Share of Common Stock*	0.53	2.12	2.12	2.12	2.12
Shares of Common and Common Stock Equivalents (Average)	37,920	34,026	25,458	21,883	16,539
Ratio of Earnings to Fixed Charges	2.54	2.96	2.47	2.36	2.32
Unfinished Construction	$1,691,455	$1,398,134	$1,027,608	$ 772,526	$ 724,150
Total Assets	2,565,283	2,085,783	1,615,523	1,328,349	1,254,228
Long-Term Debt	999,601	726,777	637,808	449,071	398,856
Preferred Stock with Mandatory Redemption Requirements	265,220	271,280	177,840	120,000	120,000
Total Capitalization	2,228,661	1,811,408	1,465,102	1,090,535	957,604
Short-Term Debt	145,485	—	—	125,600	108,350

* Since April 1984 the Company has omitted the quarterly dividends payable on shares of Common and Preferred Stock.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Capital Requirements and Liquidity

The Company's external financing requirements for the period 1985-1989 total approximately $683 million. Through a financing completed in December 1984, the Company has provided for its estimated working capital needs until the estimated completion date of Seabrook Unit 1. The majority of the external financing is needed for funding construction expenditures of $616.1 million and refinancing of debt maturities and payment of sinking fund requirements of approximately $410.0 million. It is anticipated that the balance of funds required will be generated internally in the years 1988 and 1989. See Item 1, *Financing — Five Year Program.*

Until completion of Unit 1 of the Seabrook Plant, the Company's earnings are expected to consist almost entirely of AFUDC, which is described in Note 2 of Notes to Financial Statements. Since AFUDC is a non-cash addition to earnings, cash for the payment of interest on the Company's outstanding indebtedness and the indebtedness to be incurred to complete construction of Unit 1 will need to be provided in large part by external financing. The Company's ability to accomplish its financing program has been impaired as a result of a serious liquidity crisis experienced in the spring of 1984 which threatened to require the Company to seek protection from its creditors under the Bankruptcy Code. At this time the Company is unable to obtain any significant amount of additional short-term bank credit and does not believe it can sell any additional shares of its Preferred or Common Stocks on reasonable terms as a result of its omission since April 1984 of dividends on its Common and Preferred Stocks. Consequently, at least until the Company has paid all arrearages in dividends on shares of its Preferred Stocks, the Company is required to satisfy all of its external financing requirements through the issuance of debt instruments in the securities markets. See Item 1, *Financing — Liquidity Crisis*.

Holders of $146 million of indebtedness may demand immediate payment if the financing described under Item 1, *Financing — Newbrook Plan* is not consummated by February 28, 1985, current estimates of the cost and completion date of Seabrook Unit 1 exceed earlier estimates, or certain minimum spending levels for construction of Seabrook Unit 1 are not achieved by February 28, 1985. The Company is in the process of seeking amendments of these and certain other provisions of these agreements and waivers of certain defaults. It is likely that further amendments will be needed by the end of March 1985.

The Company's cash flow will improve as Seabrook Unit 1 is reflected in rates. See Item 1, *Seabrook Nuclear Plant — Rate Treatment*. Delay in commercial operation of Unit 1 or in the reflection in rates of a substantial portion of the costs of Unit 1 would require the Company to obtain significant amounts of additional external financing, and there can be no assurance that the Company would be able to obtain such financing. The amount of the costs of constructing Unit 1 includible in the Company's rate base upon completion of Unit 1 is expected to be the subject of controversy in the NHPUC proceeding considering the matter. Allegations have been made that construction of Unit 1 has been mismanaged and that such mismanagement has resulted in excessively high costs. See Item 3, *Other*. Only costs found by the NHPUC to have been prudently incurred would be included in the Company's rate base. Future earnings would be adversely affected to the extent that the full costs of Unit 1 were not reflected in rates. Even after inclusion of Unit 1 in rate base, any outage of Unit 1 of such a nature or duration as to result in its removal from rate base would impose significant burdens on the Company because Unit 1 and common facilities will constitute more than half of the Company's total assets and will be the source of a significant portion of its electric generating capacity.

The Company's ability to successfully implement its financing program is dependent upon completing construction of Seabrook Unit 1, obtaining an operating license for Unit 1 from the NRC, and reflecting in rates the costs of Unit 1 as described under Item 1, *Business — Seabrook Nuclear Plant*.

Results Of Operations

Operating revenues increased 13% in 1984 as significant economic and population growth occured in the area served by the Company. This increase followed the 9% increase of 1983 and a 4% decline in revenues of 1982. The increases in 1984 and 1983 revenues were primarily the result of increased megawatt-hour sales (6.1% and 3.6%, respectively) and the rate changes which are discussed in Note 3 of Notes to Financial Statements. The revenue change of 1982 was primarily the result of rate changes as megawatt-hour sales declined slightly in that year.

Fuel and purchased power expenses, on which energy cost recovery revenues are based, are the major component of operating expenses comprising 59% of the total operating expenses for each year. While the effect of variations in energy costs has had a significant effect on the Company's revenues in the past, the stability of energy prices in recent years has produced small energy related changes in revenues and expenses.

Operating expenses other than fuel, purchased power expenses and taxes on income decreased slightly for 1984 and 1983, significant reductions from the 14% increase of 1982. This reduction reflects the lessened impact of inflation, cash conservation and the continuing development of strict cost control and efficiency measures in all areas of the Company's operations.

The increase in operating revenues coupled with certain operating expense decreases produced a significant improvement in operating income for 1984 and 1983. AFUDC increased in each year due to the increase in unfinished construction at the Seabrook Plant.

Effective March 1, 1984, the Company ceased capitalization of all costs, including AFUDC, related to Unit 2 of the Seabrook Plant. The effect of this decision was to reduce 1984 net income by approximately $35,200,000.

Interest on long-term debt has increased each year as the balance of debt outstanding has increased due to the capital requirements of the Company's construction program. In 1984 other interest expense increased as some long-term debt agreements were restructured to short-term during the liquidity crisis experienced in 1984. The issuance of $90,000,000 of short-term notes in June, 1984, which were exchanged for long-term debt in December 1984, also increased other interest expense. Other interest expense declined in 1983 as the use of short-term borrowings was reduced.

Net income increased in all periods, but in 1983 the improvement was more pronounced primarily due to increased AFUDC and increased megawatt-hour sales. In 1984 the improvement was diminished as the cessation of the capitalization of costs related to Unit 2 offset the effect of increased megawatt-hour sales.

Preferred dividend requirements increased in 1984 and 1983 as preferred stock was issued in April and October of 1983.

In December 1984, the Company issued 18,375,000 common stock purchase warrants as part of a $425 million financing. As the warrants are common stock equivalents, the effect of their issuance was to reduce earnings per share slightly in 1984. In 1985 the effect will be more pronounced. See Note 2 of Notes to Financial Statements.

Inflation continued to affect Company operations, since under current regulatory practice the investment in utility plant is recovered at historical cost but replaced, as necessary, at current cost. See Note 10 of Notes to Financial Statements, which reflects the approximate effects of inflation on Company operations. The data provided in Note 10 have been prepared and presented in conformity with guidelines established by the Financial Accounting Standards Board and should be viewed as experimental and only approximations of certain effects of inflation on operations of the Company.

If Seabrook Unit 2 is cancelled and the Company is denied recovery through rates, the unrecovered cost would be charged against earnings in the period when such denial became final. In addition, to the extent that costs of constructing Unit 1 are not allowed in rate base, the Company might be required to charge the disallowed amount against earnings. Under certain circumstances, the aggregate of such charges could eliminate or even result in a deficit in the Company's retained earnings.

The results of operations discussed above are not necessarily indicative of future earnings. It is expected that higher operating costs and carrying charges on increased investment in plant, if not offset by a similar increase in operating revenues (produced either by periodic rate relief or increases in megawatt-hour sales), will adversely affect future earnings. Continued growth in megawatt-hour sales will be dependent on the rate of economic growth in New Hampshire, weather and the use of alternate energy sources.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

STATEMENTS OF EARNINGS

	For the Year Ended December 31,		
	1984	1983	1982
		(Thousands of Dollars)	
Operating Revenues (Note 3)			
Residential	$187,479	$166,058	$153,184
Industrial	138,430	119,958	114,380
Other	199,676	177,468	155,726
Total Operating Revenues	525,585	463,484	423,290
Operating Expenses			
Operation			
Fuel	173,812	127,504	113,091
Purchased and Interchanged Power	84,504	107,467	111,739
Other Operating Expenses	58,581	56,608	57,890
Maintenance	19,267	27,000	29,642
Depreciation	22,728	21,016	19,558
Taxes on Income (Note 4)	56,119	34,968	29,425
Other Taxes, Principally Property Taxes	23,330	20,771	18,476
Total Operating Expenses	438,341	395,334	379,821
Operating Income	87,244	68,150	43,469
Other Income and Deductions			
Allowance for Equity Funds Used During Construction (Note 2)	103,912	104,146	67,624
Taxes on Income (Note 4)	49,179	30,185	24,661
Equity in Earnings of Affiliated Companies	3,122	2,856	3,099
Other — Net	424	4,891	2,906
Total Other Income and Deductions	156,637	142,078	98,290
Income Before Interest Charges	243,881	210,228	141,759
Interest Charges			
Interest on Long-Term Debt	105,482	85,649	61,169
Other Interest	21,920	6,122	19,015
Allowance for Borrowed Funds Used During Construction (Note 2)	(40,121)	(33,201)	(30,048)
Net Interest Charges	87,281	58,570	50,136
Net Income	156,600	151,658	91,623
Preferred Dividend Requirements (Note 8)	40,983	32,996	22,153
Earnings Available for Common Stock	$115,617	$118,662	$ 69,470
Weighted Average Common and Common Equivalent Shares (000's)	37,920	34,026	25,458
Earnings Per Common and Common Equivalent Share (Note 2)	$3.07	$3.49	$2.73
Dividends Per Share of Common Stock (Note 8)	$0.53	$2.12	$2.12

See accompanying Notes to Financial Statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

BALANCE SHEETS

ASSETS

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
Utility Plant at Original Cost		
Electric Plant	$ 684,086	$ 639,688
Less: Accumulated Provision for Depreciation	219,355	201,044
	464,731	438,644
Unfinished Construction (Note 1)		
In Progress (Principally Seabrook Unit 1)	1,389,555	1,095,034
Suspended (Seabrook Unit 2)	301,900	303,100
Total Unfinished Construction	1,691,455	1,398,134
Net Utility Plant	2,156,186	1,836,778
Investments		
Nuclear Generating Companies	11,600	11,544
Finance Subsidiary	12,486	13,258
Real Estate Subsidiary	7,619	8,227
Other, at Cost	184	185
Total Investments	31,889	33,214
Current Assets		
Cash and Temporary Investments	262,256	82,487
Accounts Receivable (Net of Allowance of $959 and $875 in 1984 and 1983, respectively)	47,021	50,277
Unbilled Revenue	10,560	9,220
Fuel, Materials and Supplies, at Cost	28,311	45,840
Other	4,943	5,093
Total Current Assets	353,091	192,917
Other Assets		
Special Deposits	2,431	205
Cost of Cancelled Pilgrim Unit 2 Project (Note 1)	15,646	15,931
Other	6,040	6,738
Total Other Assets	24,117	22,874
	$2,565,283	$2,085,783

See accompanying Notes to Financial Statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
Capitalization (See separate statements)		
Common Stock Equity	$ 915,127	$ 764,368
Preferred Stock		
With Mandatory Redemption Requirements	265,220	271,280
Without Mandatory Redemption Requirements	48,713	48,983
Long-Term Debt	999,601	726,777
Total Capitalization	2,228,661	1,811,408
Current Liabilities		
Notes Payable (Note 5)	20,485	—
Promissory Note (Note 5)	25,000	—
Eurodollar Term Loan (Note 5)	50,000	—
Nuclear Fuel Obligation (Note 5)	50,000	—
Long-Term Debt to be Retired Within One Year	20,430	96,439
Preferred Stock Redemption Due Within One Year	7,620	1,560
Accounts Payable	32,111	75,910
Accrued Taxes	7,959	8,113
Accrued Interest	39,384	23,194
Other	19,321	8,953
Total Current Liabilities	272,310	214,169
Deferred Credits		
Accumulated Deferred Investment Tax Credits	18,063	18,562
Accumulated Deferred Taxes on Income (Note 4)	43,811	38,722
Other	2,438	2,922
Total Deferred Credits	64,312	60,206
Commitments and Contingencies (Note 1)		
	$2,565,283	$2,085,783

See accompanying Notes to Financial Statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

STATEMENTS OF CAPITALIZATION

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
Common Stock Equity		
Common Stock — $5 Par Value(a)		
Authorized — 60,000,000 Shares		
Outstanding — 37,191,067 Shares in 1984, and 36,996,327 in 1983	$185,955	$184,982
Other Paid-In Capital	436,320	413,275
Retained Earnings(b)	292,852	166,111
Total Common Stock Equity	915,127	764,368
Cumulative Preferred Stock (Note 8)		
Par Value $100 Per Share — Authorized 1,350,000 Shares		
Outstanding 615,528 Shares		
Par Value $25 Per Share — Authorized 14,000,000 Shares		
Outstanding 10,400,000 Shares		

Dividend	Par Value	Shares Outstanding	Call Price	1984	1983
With Mandatory Redemption Requirements(c)					
7.64%	$100	120,000	$104.84	12,000	12,000
9.00	100	158,400	106.75	15,840	15,840
11.24	25	1,200,000	27.11	30,000	30,000
17.00	25	1,200,000	29.25	30,000	30,000
15.00	25	1,200,000	28.75	30,000	30,000
15.44	25	2,400,000	28.86	60,000	60,000
13.00	25	1,400,000	28.25	35,000	35,000
13.80	25	2,400,000	28.45	60,000	60,000
				272,840	272,840
Less: Preferred Stock Redemption Due Within One Year				(7,620)	(1,560)
				265,220	271,280
Without Mandatory Redemption Requirements					
3.35%	$100	102,000	$100.00	10,200	10,200
4.50	100	75,000	102.00	7,500	7,500
5.50 (Convertible)	100	10,128	100.00	1,013	1,283
7.92	100	150,000	103.96	15,000	15,000
11.00	25	600,000	27.00	15,000	15,000
				48,713	48,983
Total Cumulative Preferred Stock — Net				313,933	320,263

See accompanying Notes to Financial Statements and to Statements of Capitalization.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

STATEMENTS OF CAPITALIZATION

	Series	Rate	Maturity	December 31, 1984	December 31, 1983
				(Thousands of Dollars)	
Long-Term Debt(d)					
First Mortgage Bonds(e)					
	H	3¼%	1984	$ —	$ 10,080
	I	3⅞	1986	6,710	6,710
	M	4⅝	1992	21,212	21,259
	N	6⅛	1996	15,345	15,345
	O	6¼	1997	13,624	13,624
	P	7⅛	1998	13,705	13,705
	Q	9	2000	18,490	18,490
	R	7⅝	2002	18,705	18,705
	S	9	2004	18,957	18,957
	U	10¾	1985	14,125	14,128
	V	9⅛	2006	14,478	14,478
	W	10⅛	1993	9,796*	9,864*
	X	12	1999	9,244*	9,302*
	Y	18	1989	24,135*	24,135*
				198,526	208,782
Less: First Mortgage Bonds(*) Pledged as Security for General and Refunding Mortgage Bonds				(43,175)	(43,301)
Total First Mortgage Bonds				155,351	165,481
General and Refunding Mortgage Bonds					
	A	10⅛%	1993	49,080	54,540
	B	12	1999	60,000	60,000
	C	14½	2000	30,000	30,000
	D	17	1990	23,000	23,000
	E	18	1989	50,000	50,000
	G	Variable Rate	1987	17,563**	—
Less: General and Refunding Mortgage Bonds(**) Pledged as Security for Nuclear Fuel Obligation				(17,563)	—
Promissory Note (Note 5)				—	25,000
Eurodollar Term Loan (Note 5)				—	50,000
Promissory Notes, 17%, Due 1986				30,000	30,000
Pollution Control Revenue Bonds					
		9 %	1984	—	5,800
		12¼–13¾	1988-2003	20,000	20,000
Debentures					
		15¾%	1988	75,000	75,000
		14⅜	1991	100,000	100,000
		15	2003	100,000	100,000
		17½	2004	425,000	—
Nuclear Fuel Obligation (Note 5)				—	50,000
Total Long-Term Debt				1,117,431	838,821
Less: Long-Term Debt to be Retired Within One Year				(20,430)	(96,439)
Unamortized Premium and Discount				(97,400)	(15,605)
Long-Term Debt — Net				999,601	726,777
Total Capitalization				$2,228,661	$1,811,408

See accompanying Notes to Financial Statements and to Statements of Capitalization.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

NOTES TO STATEMENTS OF CAPITALIZATION

(a) In December 1984 the Company issued 18,375,000 warrants which will allow the holder to purchase a share of Common Stock at an exercise price of $5.00 per share. The warrants expire in 1991.

(b) Since April 1984 the Company has omitted dividends on its Common and Preferred Stocks. There are currently $40,981,304 of Preferred Stock dividends in arrears. No dividends may be paid on Common Stock until such dividends are paid. Terms of certain short-term indebtedness prohibit the payment of Common Stock dividends until $125,000,000 of such debt is repaid. The Company's agreement with certain of its lenders contains further restrictions on the payment of dividends. In its September 1984 order approving a $425 million financing, the NHPUC imposed a condition that the Company not pay preferred and common dividends until authorized to do so by further NHPUC order.

Pursuant to the terms of the General and Refunding Mortgage Indenture, dividends may not be paid on the Common Stock in excess of net income accumulated after January 1, 1978 less the aggregate amount of all dividends paid or declared on the Preferred Stock of the Company during such period plus $32,000,000. At December 31, 1984, retained earnings of $230,282,000 were not subject to dividend restriction.

(c) The annual Sinking Fund requirements for Preferred Stock with mandatory redemption requirements are as follows: 1985 — $7,620,000, 1986 — $6,060,000, 1987 — $9,060,000, 1988 — $10,810,000 and 1989 — $13,810,000. Terms of short-term indebtedness prevent the Company from making these payments.

(d) The Long-Term Debt Maturities and annual Sinking Fund requirements are as follows: 1985 — $20,430,000, 1986 — $43,768,000, 1987 — $7,058,000, 1988 — $85,308,000 and 1989 — $61,558,000. Under the terms of the First Mortgage Indenture and the General and Refunding Mortgage Indenture, substantially all utility property of the Company is subject to the liens thereof.

(e) Due to certain restrictions in the Company's First Mortgage Indenture, no significant amount of First Mortgage Bonds may be issued until an operating license is obtained for Seabrook Unit 1. See Item 1, *Seabrook Nuclear Plant — Seabrook Unit 1.*

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

STATEMENTS OF CHANGES IN FINANCIAL POSITION

	For the Year Ended December 31, 1984	1983	1982
	(Thousands of Dollars)		
Source of Funds			
From Operations			
Net Income	$ 156,600	$ 151,658	$ 91,623
Principal Non-Cash Charges (Credits) to Income			
Depreciation	22,728	21,016	19,558
Allowance for Equity Funds Used During Construction	(103,912)	(104,146)	(67,624)
Deferred Taxes and Investment Credit Adjustments	4,590	11,778	(192)
Total from Operations	80,006	80,306	43,365
From Outside Sources			
Sale of Long-Term Debt	341,706	235,413	141,050
Sale of Preferred Stock	—	95,000	60,000
Sale of Common Stock and Warrants	23,841	185,288	49,886
Nuclear Fuel Obligation	—	50,000	—
Funds Deposited with Trustee	—	18,133	—
Change in Short-Term Borrowings	145,485	—	(164,600)
Sale of Portion of Millstone Unit 3	—	—	15,353
Subsequent Financings Used to Reduce Notes Payable — Banks	—	(164,600)	164,600
Total from Outside Sources	511,032	419,234	266,289
Decrease in Working Capital	—	40,621	23,720
Total	$ 591,038	$ 540,161	$ 333,374
Application of Funds			
Property Additions	$ 342,984	$ 425,909	$ 304,968
Allowance for Equity Funds Used During Construction	(103,912)	(104,146)	(67,624)
Dividends	29,859	103,865	75,200
Reduction of Long-Term Debt	70,381	97,238	13,930
Reduction of Preferred Stock	6,060	1,560	2,160
Increase in Working Capital	247,518	—	—
Special Deposits	2,226	205	15,092
Other Applications — Net	(4,078)	15,530	(10,352)
Total	$ 591,038	$ 540,161	$ 333,374
Increase (Decrease) in Working Capital Other Than Short-Term Borrowings			
Cash and Temporary Investments	$ 179,769	$ 80,727	$ (3,359)
Receivables	(3,256)	6,566	(291)
Inventories	(17,529)	(322)	16,125
Long-Term Debt to be Retired Within One Year	76,009	(90,352)	(1,087)
Preferred Stock Redemption Due Within One Year	(6,060)	(480)	(1,080)
Accounts Payable	43,799	(15,995)	(28,307)
Accrued Taxes	154	(6,160)	4,456
Accrued Interest	(16,190)	(5,027)	(1,013)
Other	(9,178)	(9,578)	(9,164)
Total	$ 247,518	$ (40,621)	$ (23,720)
Composition of Property Additions			
Jointly-Owned Nuclear Facilities	$ 293,574	$ 365,752	$ 255,988
Nuclear Fuel	11,671	12,305	10,843
Other	37,739	47,852	38,137
Total	$ 342,984	$ 425,909	$ 304,968

See accompanying Notes to Financial Statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

For the Three Years Ended December 31, 1984

		(Thousands of Dollars)			
	Shares	Amount at Par Value	Other Paid-In Capital	Retained Earnings	Total
Balance — December 31, 1981	23,195,639	$115,978	$253,934	$101,909	$471,821
Add (Deduct)					
Net Income				91,623	91,623
Cash Dividends —					
Common Stock				(54,202)	(54,202)
Preferred Stock				(20,998)	(20,998)
Issuance of Common Stock	3,328,044	16,640	33,279		49,919
Issuance Cost of Preferred Stock			(2,538)		(2,538)
Amortization of Redeemed Preferred Stock Issuance Cost			7	(7)	
Balance — December 31, 1982	26,523,683	$132,618	$284,682	$118,325	$535,625
Add (Deduct)					
Net Income				151,658	151,658
Cash Dividends —					
Common Stock				(72,458)	(72,458)
Preferred Stock				(31,407)	(31,407)
Issuance of Common Stock	10,472,644	52,364	132,671		185,035
Issuance Cost of Preferred Stock			(4,085)		(4,085)
Amortization of Redeemed Preferred Stock Issuance Cost			7	(7)	
Balance — December 31, 1983	36,996,327	$184,982	$413,275	$166,111	$764,368
Add (Deduct)					
Net Income				156,600	156,600
Cash Dividends —					
Common Stock				(19,610)	(19,610)
Preferred Stock				(10,249)	(10,249)
Issuance of Common Stock and Warrants	194,740	973	23,097		24,070
Issuance Cost of Preferred Stock			(52)		(52)
Balance — December 31, 1984	37,191,067	$185,955	$436,320	$292,852	$915,127

See accompanying Notes to Financial Statements.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

NOTES TO FINANCIAL STATEMENTS

1. Commitments and Contingencies

The Company's shares of total expenditures included in Unfinished Construction for the jointly-owned nuclear facilities in which it is participating are as follows:

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
Seabrook Unit 1 and Common Facilities	$1,274,400	$1,011,900
Seabrook Unit 2	301,900	303,100
Millstone Unit 3	92,100	65,600
	$1,668,400	$1,380,600

The Company's construction program expenditures (excluding AFUDC) are estimated to be $249,300,000 for 1985, $157,100,000 for 1986 and $209,700,000 for 1987 through 1989.

In order to complete this construction program the Company needs to accomplish the $340 million financing described below and extend the maturity of approximately $145 million of short term debt which expires on May 31, 1985, until the estimated completion date of Seabrook Unit 1. The Company is seeking approval from the NHPUC for the $340 million financing, but is unable to determine whether such approval will be granted.

The Seabrook Plant has experienced persistent and substantial cost increases. The increased costs have been due, among other reasons, to design changes, revisions of regulations of and other actions by the NRC and other regulatory bodies, extraordinarily high interest rates, inflation and construction delays, all of which have resulted in total costs (including AFUDC) far higher than planned. The estimates of cost and completion dates for the Seabrook Plant released in March 1984 were about 75% greater and 18 months later, respectively, than those made by the Plant's architect/engineer in November, 1982.

Following announcement of the substantial increase in the estimated cost of the Seabrook Plant on March 1, 1984, the Company's commercial banks indicated that they were unwilling to make advances under their $160,000,000 Revolving Credit Agreement with the Company (under which no amounts were outstanding) unless the Company obtained back-up sources of credit. Because funds were no longer available to the Company under the Revolving Credit Agreement, it was necessary for the Company to commence strict cash conservation measures which included a vote by the Board of Directors on April 19, 1984 to omit the quarterly dividends payable on May 15, 1984 on shares of Common and Preferred Stocks and suspension on April 18, 1984 of payment of the Company's share of Seabrook Plant construction costs. The Company reduced non-Seabrook construction, began a program of reducing the number of non-Seabrook employees and reduced the salaries of executive officers and certain other salaried employees. The Company ceased the oil-to-coal conversion of three 50 MW units at its Schiller Station, which had been scheduled to be completed by the end of 1984. The payment of principal in the amount of $5,000,000 was not made when due under the Company's Acceptance and Stand-By Revolving Credit Facility Agreement with certain banks. Consequently, the banks terminated their commitments to provide further loans under this Agreement. As a result of the foregoing nonpayment, the commercial banks terminated their commitment to make loans under the Revolving Credit Agreement. The Company did not pay when due the May 1, 1984 installment on its Nuclear Material Lease and Security Agreement with PruLease, Inc. under which a borrowing of $50,000,000 was outstanding secured by a lien on the Company's interest in nuclear fuel for the Seabrook Plant. In consequence, PruLease, Inc. terminated the Agreement and demanded payment of all outstanding unpaid rents, the outstanding principal of all borrowings and all additional losses, damages and expenses associated with the Company's actions. The foregoing payment defaults were cured on June 20, 1984 when the Company sold $90,000,000 principal amount of its Secured Exchangeable Promissory Notes 20% due 1985 and applied a portion of the proceeds toward the payment of outstanding debts.

1. Commitments and Contingencies — (Continued)

Construction of Unit 1 was suspended by the Company during April 1984, and resumed on July 2 at an approved expenditure level averaging $4 million per week. By action of the Joint Owners the expenditure level was increased to $5 million per week commencing December 1, 1984. The Company believes that this expenditure limit will remain in effect until regulatory authorities have issued orders permitting the completion of Seabrook Unit 1. If this expenditure limit were lifted effective April 1, 1985, the commercial operation date would be October 31, 1986, and the total cost of Unit 1 would be $4.6 billion including AFUDC at a composite rate for all Joint Owners of $1.7 billion and a management contingency allowance of $170 million, but excluding uranium fuel. The Company's share of this cost would be $1,809,700,000 (including AFUDC of $759,200,000 but excluding uranium fuel of $98,000,000). This estimate is based on the assumption that the expenditure limit will be removed effective April 1, 1985 and that Seabrook Plant construction management is able to plan in advance for removal of the limit so as to ensure optimum construction scheduling. However, it is now unlikely that the expenditure limit will be completely removed by that date. The Company anticipates that revised estimates for Seabrook Unit 1 will be made after the expenditure limit has been removed.

In December, 1984 the Company completed a $425 million face amount financing that resulted in net cash proceeds to the Company of $275 million and conversion of $90 million of short term debt to long term debt. Completion of this financing and an earlier financing of $90 million has allowed the Company to continue to pay its share of the costs of constructing Seabrook Unit 1.

In its order approving the above financing the NHPUC stated that the Company could "service Seabrook related debt and accrue Seabrook related AFUDC at current levels until an order is issued" in the NHPUC proceeding which is considering whether to approve the Company's plan to raise its share of the cost to complete Seabrook Unit 1, and that the Company could not service such debt from the proceeds of these financings or accrue such AFUDC after the conclusion of that proceeding unless specifically authorized by the NHPUC to do so at that time. Until approval of the Company's plan to raise its share of the cost to complete Seabrook Unit 1, the Company will not use any of the proceeds from the $425 million financing to pay for its share of Seabrook construction costs or to service indebtedness which could be characterized as "Seabrook related debt".

Until Unit 1 is completed and a substantial portion of its costs is reflected in rates, the Company will require external financings to pay interest on its outstanding obligations and complete construction. The Company's inability to obtain any significant amount of additional short-term bank credit requires the Company to satisfy all of its external financing requirements in the securities markets. The Company believes that it is presently unable to sell its Preferred and Common Stocks on reasonable terms, principally because of the omission of dividends on those securities since April 1984. The Company's ability to issue debt securities is dependent upon many factors, some of which are beyond the Company's control. This lack of financial flexibility may impair the Company's ability to meet its obligations as they become due, satisfy covenants in its existing obligations or complete construction of Unit 1. If construction of Unit 1 were not completed, or commercial operation were unduly delayed, or adequate rate relief were not granted the Company upon commercial operation of the Unit, it would be very difficult for the Company to avoid proceedings under the Bankruptcy Code.

On August 24, 1984, the Company signed agreements with its existing lenders which restructured the Company's indebtedness held by banks and its agreement with PruLease, Inc. This restructuring extends the maturity of an aggregate of $75 million of bank debt to May 31, 1985, and is subject to certain conditions regarding financing and construction (including consummation of the $340 million financing described below by February 28, 1985). If these conditions are not met, payment

1. Commitments and Contingencies — (Continued)

of the bank debt may be immediately demanded by the banks. The Company is in the process of seeking amendments and extensions of the agreement. The $50 million of restructured financing by PruLease, Inc. has the same conditions and rights of acceleration. Extension of the maturity of any of these financings is dependent upon extension of the others on terms satisfactory to each lender.

The Company's cash flow will be improved when Seabrook Unit 1 is reflected in rates. Delay in commercial operation of Unit 1 or in the reflection in rates of a substantial portion of the costs of the Unit would require the Company to obtain significant amounts of external financing. The amount of the costs of constructing Unit 1 includible in the Company's rate base upon completion of Unit 1 is expected to be the subject of controversy in the NHPUC proceeding considering the matter. Allegations have been made that construction of Unit 1 has been mismanaged and that such mismanagement has resulted in excessively high costs. Only costs found by the NHPUC to have been prudently incurred would be included in the Company's rate base. Future earnings would be adversely affected to the extent that the full costs of Unit 1 were not reflected in rates. Even after inclusion of Unit 1 in rate base, any outage of Unit 1 of such a nature or duration as to result in its removal from rate base would impose significant burdens on the Company because Unit 1 and common facilities will constitute more than half of the Company's total assets and will be the source of a significant portion of its electric generating capacity.

The Company's financing plan assumes that the costs associated with Seabrook Unit 1 will be reflected in rates on a phased-in basis after Unit 1 begins commercial operation. On July 23, 1984 the Company announced that it would seek to recover through rates no more than its actual share of a $4.5 billion aggregate cost of construction of Unit 1, contingent upon (1) the occurrence of no catastrophic developments clearly outside the control of construction management and (2) the timely receipt of regulatory approvals by the Joint Owners for financing the construction completion costs and for the change in management structure. The Company believes its acceptance of a limit on the total cost of the Unit for rate-making purposes should increase the feasibility of phasing the Unit into rates on an acceptable basis. For financial planning purposes, the Company is assuming that Unit 1 could be phased into rates over a number of years with annual increases of about 10% plus a yearly inflation adjustment of about 5%. A phase-in of Unit 1 could result in the deferral by the Company of very large amounts of revenue which would have been collected had the entire cost of the Unit been placed into rates immediately. The ultimate recovery of these deferred revenues will require that the Company obtain rate increases each year for a number of years beyond the 1985-1989 period. The Company cannot predict whether cumulative rate increases of a size required to recover the Company's investment in the Unit will be granted by the NHPUC.

As part of a plan to complete the construction of Unit 1 of the Seabrook Plant each Seabrook Joint Owner submitted to the other Joint Owners (i) a plan for raising funds sufficient to pay for such Joint Owner's share of the remaining cost to complete Unit 1 and (ii) a schedule for regulatory approvals of such plan. The plans assume a cash cost to complete construction of Unit 1 of $1.0 billion and a commercial operation date in October 1987. Each of such plans and schedules was approved by the other Joint Owners. In order to obtain such approval each Joint Owner had to evidence that the required financing would be available by satisfying certain criteria.

To fulfill its commitment under this Newbrook Plan, the Company intends to issue in the second quarter of 1985 up to $525 million principal amount of debt securities, designed to yield proceeds to the Company of $340 million. These securities will likely be of two types: deferred interest, third mortgage bonds issued directly to the public ("DIBS") and third mortgage bonds issued to secure pollution control revenue bonds to be issued by the New Hampshire Industrial Development Authority on behalf of the Company. It is contemplated that the DIBS will not require interest payments for a period of up to two years and will be issued at a discount from their principal amount. The

1. Commitments and Contingencies — (Continued)

discount is designed to approximate compound interest on the amount paid by the purchasers of the bonds for the period during which interest is not paid. Thereafter interest would accrue and be payable semi-annually. All of these bonds would be secured by a third mortgage on substantially all of the Company's property located in New Hampshire. The proceeds received by the Company after underwriting discounts and expenses will enable the Company to deposit into the escrow account funds sufficient to pay its share of the remaining estimated construction costs of Seabrook Unit 1.

The issuance of these securities is currently the subject of protracted hearings before the NHPUC. The Company expects an order in this proceeding by March 31, 1985. However, due to an uncertainty in New Hampshire law, the Company may not be able to issue such securities until all appeals of the NHPUC order have been decided by the New Hampshire Supreme Court. Such a decision may not be rendered for two months or more after the NHPUC order has been issued. Certain other regulatory bodies have imposed deadlines that require that all Joint Owners complete their financing for Unit 1 by April 15, 1985 or that require removal of the expenditure limit on the construction of Unit 1 by May 5, 1985. If the securities are not issued by April 15, 1985 or the construction limit is not lifted by May 5, 1985, certain other Joint Owners may have to return to their commissions for further hearings or new proceedings, the result of which cannot be predicted. In the event of a negative ruling by the NHPUC regarding the issuance of these securities or the inability of the Joint Owners to complete their financings, Seabrook Unit 1 may not be completed and it will be difficult for the Company to avoid proceedings under the Bankruptcy Code.

If, due to regulatory action, financial difficulties or any other reason, one or more of the other Seabrook Plant participants should be unable to obtain sufficient or timely rates and financing and consequently are unable to fulfill their contractual commitments to pay on a timely basis their share of Unit 1 construction costs, completion of Unit 1 would be jeopardized. Delays in construction or licensing of Unit 1, adverse regulatory or legislative action, financing problems of the Company, work stoppages, labor or material shortages or further administrative or court decisions relating to actions of regulatory agencies, may jeopardize the completion of Unit 1. If Unit 1 is not completed, it would be very difficult for the Company to avoid proceedings under the Bankruptcy Code.

In order to commence commercial operation of Unit 1, it is necessary to obtain an operating license from the NRC. The Company's request for the Unit 1 operating license is being actively opposed by intervenors in hearings before the NRC. In order to obtain the license, it is necessary to develop the emergency response and evacuation plans for the Seabrook Plant in conjunction with federal, New Hampshire and Massachusetts agencies and 24 municipalities in New Hampshire and Massachusetts. Several municipalities and the Massachusetts Attorney General are opposing such development or the adequacy of the proposed procedures and plans, and the Governor of Massachusetts has indicated that he will not certify the Massachusetts plan to the appropriate federal agency unless all Massachusetts municipalities involved have approved their respective plans.

Currently, there are no viable plans for the completion of construction of Unit 2, and the Company does not have current cost or commercial operation date estimates. Under the Joint Ownership Agreement, cancellation of Unit 2 can only be effected by the vote of at least 80% of the ownership interests, so that cancellation requires the Company's concurrence in such a vote. However, the Joint Ownership Agreement requires the vote of at least 51% of the ownership interests to resume construction of Unit 2, and resumption of construction by the present Joint Owners is extremely unlikely. The Company's financing plans assume no further spending for Unit 2.

If Unit 2 is cancelled, the Company would petition the NHPUC for recovery of its investment in Unit 2 from ratepayers. The Company cannot predict what action the NHPUC would take. In

1. Commitments and Contingencies — (Continued)

view of the recent decision of the New Hampshire Supreme Court regarding the Pilgrim Unit 2 generating plant (discussed below), it is uncertain whether the NHPUC can grant the Company recovery of its investment in Seabrook Unit 2 from ratepayers, should that Unit be cancelled. If the NHPUC denied recovery and subsequent administrative and judicial appeals, if any, were unsuccessful, the Company would be required to charge the unrecovered cost of Unit 2 against earnings when such denial became final; the Company does not believe that a final determination of the question will be made before 1986. At December 31, 1984, the Company's investment in Unit 2 was $301,900,000, excluding cancellation charges. While the Company believes that in the event of cancellation it would be entitled to allocate some part of this investment to the cost of Unit 1, the after-tax charge against earnings in the event it is denied recovery could, depending upon the amount not recovered, approximate the amount of the Company's current investment.

Effective March 1, 1984, the Company ceased capitalization of :l costs, including AFUDC, related to Seabrook Unit 2. The effect of this decision was to reduce 198 net income by approximately $35,200,000.

In June 1984 the New Hampshire Supreme Court ruled that the New Hampshire anti-CWIP statute prohibits recovery from ratepayers of any of the Com' .ny's investment in the cancelled Pilgrim Unit 2 generating plant located in Massachusetts. The C . npany has a 3.47% interest in that plant (an investment of approximately $16 million), which was ancelled by the lead owner in 1981, and the Company had filed a petition with the NHPUC in D cember 1983 seeking recovery of its investment. The Supreme Court expressly did not reach the question of whether the statute, as so interpreted, was constitutional, or whether the Company could receive a higher rate of return based on additional risk to investors represented by the inability to recover investments in cancelled plants due to the anti-CWIP statute. If allowed to do so, the Company intends to establish the requisite factual record in proceedings before the NHPUC and then seek a final determination by the Court of the constitutional issues. The Company believes that a final determination of the recoverability of its Pilgrim Unit 2 investment will not be made before the end of 1985.

2. Summary of Accounting Policies

Regulations and Operations

The Company is subject, as to rates, accounting and other matters, to the regulatory authority of the New Hampshire Public Utilities Commission (NHPUC), the Federal Energy Regulatory Commission (FERC) and, to a lesser extent, the public utilities commissions in other New England states where the Company does business.

Investments

The Company follows the equity method of accounting for its investments in nuclear generating companies, a wholly-owned overseas finance subsidiary and a wholly-owned real estate subsidiary. The Company owns between four and seven percent of each of four New England nuclear generating companies and, pursuant to purchased power contracts, is entitled to its ownership percent of total plant output and is obligated to pay a similar share of operating expenses and returns on invested capital. Approximately 8.1%, 9.5% and 9.9% of the Company's total energy requirements were furnished by these companies in 1984, 1983 and 1982, respectively.

Utility Plant

Provision for depreciation of utility plant is computed on a straight-line method at rates based on estimated service lives and salvage values of the several classes of property. The depreciation pro-

2. Summary of Accounting Policies — (Continued)

visions were equivalent to overall effective rates of 3.73%, 3.70% and 3.65% of depreciable property for 1984, 1983 and 1982, respectively.

Maintenance and repairs of property are charged to maintenance expense. Replacements and betterments are charged to utility plant. At the time properties are retired, the cost of property retired plus costs of removal less salvage are charged to the accumulated provision for depreciation.

Operating Revenues

Revenues are based on billing rates, authorized by applicable regulatory commissions, which are applied to customers' consumption of electricity. These rates include estimates of the cost of energy incurred by the Company in the generation or purchase of electricity. To the extent that energy cost estimates differ from actual costs incurred, the differences are deferred and refunded or charged to customers through periodic rate adjustments. The Company records an estimate of revenue for service rendered but not billed.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is the estimated cost, during the period of construction, of funds invested in the construction program which is not recovered from customers through current revenues. Such allowance is not realized in cash currently but under the rate-making process the amount of the allowance is expected to be recovered in cash over the service life of the plant in the form of increased revenue collected as a result of higher plant costs.

The Company capitalized AFUDC at average net-of-tax annual rates of 11.9%, 12.0% and 11.6% for 1984, 1983 and 1982, respectively.

Earnings Per Common and Common Equivalent Share

Earnings per common and common equivalent share was calculated by adjusting earnings available for common stock for (i) the reduction in interest expense that would result from the application of the proceeds from the assumed exercise of 18,375,000 common stock purchase warrants (outstanding since December 1984 at an exercise price of $5 per share) in excess of those proceeds used to repurchase 20% of the Company's outstanding shares of common stock, to the reduction of outstanding long-term debt and (ii) the resulting change in AFUDC. The resulting earnings available for common stock was then divided by the weighted average of common stock outstanding and common stock assumed to be outstanding upon the exercise of warrants and assumed repurchases of common stock.

On a pro forma basis earnings per common and common equivalent share would have been $2.60, assuming the warrants had been issued January 1, 1984.

Ratio of Earnings to Fixed Charges

Earnings represent the aggregate of net income, less undistributed income of unconsolidated companies, plus provisions for federal and state taxes on income and fixed charges. Fixed charges represent interest, related amortization and the interest component of annual rentals.

3. Rate-Making Matters

In 1984 the NHPUC issued a rate order designed to increase annual non-energy revenues by approximately $24,700,000. During 1982, the NHPUC issued rate orders designed to increase annual non-energy revenues by approximately $9,500,000 effective July, 1982.

New Hampshire retail customers are billed a levelized energy cost rate based on six-month projected data for fuel and purchased power expense. Wholesale customers are billed under fuel adjustment clauses. The proportion of revenues from prime sales associated with energy costs were 43.9% in 1984, 46.0% in 1983 and 47.8% in 1982. The differences primarily reflect changes in the cost of energy.

4. Income Taxes

The components of income tax expense are as follows:

	1984	1983	1982
		(Thousands of Dollars)	
Included in Operating Expenses			
Current — Federal	$ 43,386	$ 31,536	$ 24,630
State	4,823	(5,674)	3,082
	48,209	25,862	27,712
Deferred — Federal	8,409	9,605	3,109
Investment Tax Credit Adjustments	(499)	(499)	(1,396)
	$ 56,119	$ 34,968	$ 29,425
Included in Other Income and Deductions			
Current — Federal	$(41,226)	$(28,672)	$(24,706)
Current — State	(4,820)	(5,056)	—
Deferred — Federal	(3,133)	3,543	45
	$(49,179)	$(30,185)	$(24,661)
Total Income Tax Expense — Federal	$ 6,937	$ 15,513	$ 1,682
State	3	(10,730)	3,082
	$ 6,940	$ 4,783	$ 4,764

In 1983, the Company reversed $10,900,000 of accrued State franchise tax liability based upon a 1982 decision of the New Hampshire Supreme Court rescinding the tax. Effective July 1983, the State of New Hampshire replaced the previous franchise tax with a 1% franchise tax on gross operating receipts which the Company recognizes as other taxes and is, therefore, not reflected in the above table.

Beginning in 1983, the Company began allocating New Hampshire Business Profits Tax to operating income taxes. An offsetting state tax benefit was allocated to other income and deductions.

Investment tax credits utilized are deferred and amortized to income over the lives of the related properties. At December 31, 1984 the Company had investment tax credits available to carry forward of approximately $90,000,000 which expire between 1994 and 1999.

The tax effect of differences between pretax income in the financial statements and income subject to tax, which are the result of timing differences, are accounted for as prescribed by and in accordance with the rate-making policies of the NHPUC. Accordingly, provisions for deferred income taxes are recognized for all specified timing differences. Taxes attributable to other timing differences are flowed through to net income as adjustments to income tax expense. As of December 31, 1984 the Company had not provided cumulative deferred income taxes totaling approximately $52,000,000 relating to various tax deductions which had been flowed through for book and ratemaking purposes. These deductions relate primarily to depreciation and unbilled revenue. Provisions for deferred income taxes are recognized for the following timing differences:

	1984	1983	1982
		(Thousands of Dollars)	
Normalized Timing Differences Relating to Plant	$ 11,645	$ 8,488	$ 7,910
Deferred Fuel Costs	(4,308)	(479)	2,104
Recoupment Revenue Recoverable	—	—	(3,302)
Accrued State Taxes	—	2,618	(1,419)
Used (Unused) Tax Net Operating Loss Carry Forward	—	3,480	(1,642)
Other	(2,061)	(959)	(497)
	$ 5,276	$ 13,148	$ 3,154

4. Income Taxes — (Continued)

The principal reasons for the differences between total income tax expense and the amount calculated by applying the federal income tax rate (46%) to income before income tax are as follows:

	1984	1983	1982
	(Thousands of Dollars)		
Income Before Income Tax	$163,540	$156,441	$ 96,387
Expected Tax Expense	$ 75,228	$ 71,963	$ 44,338
Increase (Reductions) in Taxes Resulting from			
AFUDC Equity	(47,799)	(47,907)	(31,107)
Net-of-Tax Method of Recording AFUDC	(18,249)	(15,273)	(13,822)
Difference between Book and Tax Depreciation — Not Normalized	1,969	1,829	1,505
State Income Taxes Net of Federal Income Tax	2	(5,794)	1,665
Other Deductions	(4,211)	(35)	2,185
Total Income Tax Expense	$ 6,940	$ 4,783	$ 4,764

5. Short-Term Borrowings

Short-term debt outstanding at December 31, 1984 consists of a $50,000,000 nuclear fuel obligation, $75,000,000 of bank debt and $20,485,000 of credit from the architect/engineer for the Seabrook Plant. These borrowings mature May 31, 1985 and are subject to numerous conditions regarding construction and financing of the Seabrook Plant. The interest rate on these borrowings is 116% of a specific bank's prime rate plus 0.25% except for $8,000,000 of bank debt which has an interest rate of 2½% over the London Interbank Offered Rate for three or six month Eurodollar deposits. Additionally, the Company has an agreement providing until May 31, 1985 a $35,000,000 revolving credit facility secured by the Company's accounts receivable. This facility has the same conditions as the agreements described above and numerous additional conditions to the making of loans under the facility. Borrowings under this facility have an interest rate of 108% of a specific bank's prime rate. The facility was used for a very short period in 1984, but, as a result of the completion of the financing in December 1984, the Company cannot make use of this facility and proposes to terminate it in 1985.

From June 20, 1984, until December 6, 1984, the Company had outstanding $90,000,000 of 20% short-term notes which were exchanged for units consisting of common stock purchase warrants and debentures on December 6, 1984.

Information regarding short-term borrowings is as follows:

	1984	1983	1982
	(Thousands of Dollars)		
Maximum Short-Term Borrowings	$242,485	$142,100	$141,600
Average Amount Outstanding (Based on Month-End Balances)	$132,783	$ 10,147	$104,683
Average Interest Rate (Including Fees)			
At Year End	13.23%	—	13.72%
During the Year	20.68%	24.40%	18.66%

6. Postemployment Benefits

Pension Plan. The Company has a non-contributory pension plan covering substantially all employees. The Company's policy is to fund current pension costs. Costs were $5,572,000, $5,386,000, and $5,242,000, in 1984, 1983, and 1982, respectively, and include amortization of past service costs over 25 years. Accumulated plan benefits and plan net assets for the Company's defined benefit plan as of January 1 of each year is as follows:

	1984	1983
	(Thousands of Dollars)	
Actuarial Present Value of Accumulated Plan Benefits:		
Vested	$38,562	$34,339
Nonvested	1,937	1,578
	$40,499	$35,917
Net Assets Available for Benefits	$62,022	$52,057

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 9% in 1984 and 1983.

Health Care and Life Insurance. The Company provides certain health care and life insurance benefits for employees. Substantially all of the Company's employees may become eligible to continue those benefits if they reach retirement age while working for the Company. Those benefits are provided or administered through insurance companies whose premiums or charges are based on the benefits paid during the year. The Company recognizes the cost of providing those benefits by expensing the annual insurance premiums, which were approximately $910,000 for retired employees in 1984.

7. Leases

The Company has a leasing agreement for a portion of the nuclear fuel for the Seabrook Plant. This agreement has been capitalized for financial reporting purposes. Additionally, the Company leases certain property from a wholly-owned real estate subsidiary. Costs associated with leased equipment utilized in construction are capitalized as a cost of construction.

Rentals charged to expense in 1984, 1983 and 1982 were $4,398,000, $4,344,000 and $4,463,000, respectively, including rentals paid to the wholly-owned real estate subsidiary of $1,340,000 in 1984. At December 31, 1984, estimated future minimum lease payments for noncancellable leases were as follows:

1985	$ 5,869,000
1986	4,801,000
1987	4,281,000
1988	2,755,000
1989	2,488,000
Thereafter	25,620,000
	$45,814,000

8. Preferred Dividends in Arrears

Since April 1984 the Company has omitted the quarterly dividends payable on shares of its Common and Preferred Stocks. The Preferred Stock dividends are cumulative and the Articles of Agreement of the Company require that the dividends on Preferred Stock be paid before any dividend on Common Stock can be paid.

If and when dividends payable on Preferred Stock are in arrears in an amount equal to or more than four full quarterly dividends, the holders of shares of Preferred Stock have the right to elect a majority of the Board of Directors. This condition is now in effect.

The table below indicates the amounts of dividends in arrears at February 15, 1985:

Dividend Rate	Per Share	Total
3.35%	$3.35	$ 341,700
4.50	4.50	337,500
5.50	5.50	55,704
7.64	7.64	916,800
7.92	7.92	1,188,000
9.00	9.00	1,425,600
11.00	2.75	1,650,000
11.24	2.81	3,372,000
13.00	3.25	4,550,000
13.80	3.45	8,280,000
15.00	3.75	4,500,000
15.44	3.86	9,264,000
17.00	4.25	5,100,000
		$40,981,304

9. Unaudited Quarterly Information

The following quarterly information is unaudited, and, in the opinion of management, is a fair summary of results of operations for such periods.

In the first quarter of 1984, the Company ceased capitalization of all costs, including AFUDC, related to Unit 2 of the Seabrook Plant. The effect of this decision reduced 1984 net income by approximately $35,200,000. Other variations between quarters reflect the seasonal nature of the Company's business.

	Three Months Ended							
	December 31,		September 30,		June 30,		March 31,	
	1984	1983	1984	1983	1984	1983	1984	1983
	(Thousands Except Per Share Amounts)							
Operating Revenues	$130,010	$126,773	$126,782	$117,247	$121,953	$98,829	$146,840	$120,635
Operating Income	26,817	19,545	18,521	17,674	16,928	15,091	24,978	15,840
Net Income	41,976	43,701	36,288	40,628	32,573	33,682	45,763	33,647
Preferred Dividend Requirements	10,244	9,701	10,246	8,204	10,246	8,022	10,247	7,069
Earnings Available for Common Stock	31,732	34,000	26,042	32,424	22,327	25,660	35,516	26,578
Weighted Average Common and Common Equivalent Shares	40,207	36,926	37,191	36,788	37,190	31,777	37,073	30,510
Earnings Per Common and Common Equivalent Share	$ 0.81	$ 0.92	$ 0.70	$ 0.88	$ 0.60	$ 0.81	$ 0.96	$ 0.87

10. Unaudited Information on the Effects of Changing Prices

The following supplementary information is supplied in accordance with the requirements of the Statement of Financial Accounting Standards No. 33, Financial Reporting and Changing Prices, as amended. These data are not intended as substitutes for earnings reported on a historical basis; they do, however, offer some perspective of the approximate effects of inflation rather than a precise measurement of the effects.

	Conventional Historical Cost	Current Cost Average 1984 Dollars
	(Thousands of Dollars)	
Operating revenues	$525,585	$525,585
Operation and maintenance expense	336,164	336,164
Depreciation expense	22,728	57,251
Federal and state taxes on income	56,119	56,119
Other taxes	23,330	23,330
Interest expense — net	87,281	87,281
Other income and deductions — net	(156,637)	(156,637)
	368,985	403,508
Income from continuing operations (excluding reduction to net recoverable cost)	$156,600	$122,077*
Reduction to net recoverable cost		$(41,367)
Gain from decline in purchasing power of net amounts owed		43,601
Net		$ 2,234
Effect of increase in general price level		$113,816
Increase in specific prices (current cost) of property, plant, and equipment held during the year		90,853
Excess of increase in general price level over increase in specific prices		$ 22,963

* Including the reduction to net recoverable cost, the income from continuing operations on a current cost basis would have been $80,710.

The current cost of plant was determined by indexing each major class of plant using the Handy-Whitman Index of Public Utility Construction Costs. Current cost does not necessarily represent the replacement cost of existing productive capacity since utility plant is not expected to be replaced precisely in kind. The current year's provisions for depreciation on the current cost amounts of utility plant were determined by applying the Company's depreciation rates to the indexed plant amounts. Current cost amounts reflect changes in specific prices of plant from the date the plant was acquired to the present. At December 31, 1984, current cost of property, plant and equipment, net of accumulated depreciation, was $3,167,347,000 while historical net cost was $2,156,186,000.

Fuel inventories, the cost of fuel used in generation, and the energy component of purchased power costs have not been restated from their historical cost in nominal dollars. Regulation limits the recovery of fuel and purchased power costs to actual cost incurred during the period. For this reason fuel inventories are effectively monetary assets.

10. Unaudited Information on the Effects of Changing Prices — (Continued)

Under current rate-making policies prescribed by the regulatory commissions to which the Company is subject, only the historical cost of utility property is included in the rate base upon which the Company is allowed to earn a return. Therefore, the cost of plant stated in terms of current cost that exceeds the historical cost of plant is not presently recoverable in rates, and is reflected as a reduction to net recoverable costs.

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices

STATED IN AVERAGE 1984 DOLLARS

	Year Ended December 31,				
	1984	1983	1982	1981	1980
	(Thousands except Per Share Amounts)				
Operating revenues	$525,585	$483,228	$455,502	$503,534	$442,747
Current cost information					
Income from continuing operations (excluding reduction to net recoverable cost)	122,077	122,903	65,079	56,927	44,686
Income per average common and common equivalent share (after dividend requirements on preferred stock and excluding reduction to net recoverable cost)	2.16	2.60	1.62	1.60	1.64
Increase in general price level over (under) increase in specific prices	22,963	(28,058)	(66,742)	20,729	101,100
Net assets at year-end at net recoverable cost	942,929	832,154	621,100	577,936	528,210
General information					
Gain from decline in purchasing power of net amounts owed	43,601	37,357	30,131	65,163	90,286
Cash dividends declared per common share	$ 0.53	$ 2.21	$ 2.28	$ 2.42	$ 2.67
Market price per common share at year-end	$ 3.70	$ 11.79	$ 18.62	$ 16.44	$ 17.31
Average consumer price index	311.1	298.4	289.1	272.4	246.8

10. Unaudited Information on the Effects of Changing Prices — (Continued)

Under current rate-making policies prescribed by the regulatory commissions to which the Company is subject, only the historical cost of utility property is included in the rate base upon which the Company is allowed to earn a return. Therefore, the cost of plant stated in terms of current cost that exceeds the historical cost of plant is not presently recoverable in rates, and is reflected as a reduction to net recoverable costs.

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices

STATED IN AVERAGE 1984 DOLLARS

	Year Ended December 31,				
	1984	1983	1982	1981	1980
	(Thousands except Per Share Amounts)				
Operating revenues	$525,585	$483,228	$455,502	$503,534	$442,747
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REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

The Board of Directors
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

We have examined the balance sheets and statements of capitalization of Public Service Company of New Hampshire as of December 31, 1984 and 1983 and the related statements of earnings, changes in financial position and changes in common stock equity for each of the years in the three-year period ended December 31, 1984. Our examinations ~re made in accordance with generally accepted auditing standards, and accordingly, included such : of the accounting records and such other auditing procedures as we considered necessary in th ·rcumstances.

As more fully discussed in Note 1, the March 1, 1 , cost estimate for the Seabrook Plant was substantially higher than the previous estimate. The Co..pany's short-term lines of bank credit were subsequently terminated and dividends on its common and preferred stocks have been omitted since April 1984. As a result, the Company believes that it must satisfy all of its financing requirements through the issuance of debt securities. In 1984 the Company completed financings that enabled it to pay its share of the cost of constructing Seabrook Unit 1 during 1984. The Company is seeking approval from the New Hampshire Public Utilities Commission for an additional financing to meet its estimated remaining Seabrook Unit 1 construction costs. The Company is unable to determine whether such approval will be granted. If additional financing is not obtained the Company will be unable to fund its share of the cost to complete construction of Unit 1 or to satisfy covenants in existing obligations. The commercial operation of Unit 1 is dependent upon many factors, some of which are beyond the Company's control. Those factors include the willingness and ability of the other owners of the Seabrook Plant to continue to fulfill their contractual commitments and favorable decisions from various regulatory bodies. The commercial operation of Unit 1, obtaining adequate rate relief upon commercial operation, and satisfying covenants in existing obligations are necessary for the Company to continue in existence. The accompanying financial statements do not include any adjustments relating to the recoverability and classification of recorded asset amounts or the amounts and classification of liabilities that might be necessary should the Company be unable to continue in existence.

There are currently no viable plans for the completion of Seabrook Unit 2. In 1984 the New Hampshire Supreme Court ruled that an existing statute prohibits recovery from ratepayers of any of the costs of a cancelled plant. The court did not decide whether the existing statute is constitutional. The Company intends to contest the constitutional question but it cannot predict how it will be resolved. Even if the constitutional question is resolved favorably, the Company cannot predict what, if any, recovery would be allowed. Any unrecovered costs would be charged against earnings.

In our opinion, subject to the effects on the 1984 and 1983 financial statements of such adjustments, if any, as might have been required had the outcome of (1) the uncertainty about the recoverability and classification of recorded asset amounts and the amounts and classification of liabilities referred to in the second preceding paragraph, and (2) the uncertainty about the recovery of Unit 2 costs referred to in the preceding paragraph, been known, the aforementioned financial statements present fairly the financial position of Public Service Company of New Hampshire at December 31, 1984 and 1983 and the results of its operations and changes in its financial position for each of the years in the three-year period ended December 31, 1984, in conformity with generally accepted accounting principles applied on a consistent basis.

PEAT, MARWICK, MITCHELL & CO.

Boston, Massachusetts
February 11, 1985

Item 9. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not Applicable.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item and not given in Item 4A, *Executive Officers of the Registrant*, is set forth under the caption ELECTION OF DIRECTORS in the Company's definitive proxy statement for the Company's 1985 Annual Meeting of Stockholders. Such information is hereby incorporated herein and specifically made a part hereof by reference.

Item 11. EXECUTIVE COMPENSATION

The information required by this item is set forth under the captions EXECUTIVE COMPENSATION, PENSION PLAN, EMPLOYEE STOCK OWNERSHIP PLAN, DEFERRED COMPENSATION PLAN FOR DIRECTORS AND OFFICERS and ADDITIONAL BOARD OF DIRECTORS INFORMATION in the Company's definitive proxy statement for the Company's 1985 Annual Meeting of Stockholders. Such information is hereby incorporated herein and specifically made a part hereof by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item is set forth under the captions ELECTION OF DIRECTORS and OWNERSHIP OF SHARES OF STOCK in the Company's definitive proxy statement for the Company's 1985 Annual Meeting of Stockholders. Such information is hereby incorporated herein by reference and specifically made a part hereof by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not Applicable.

PART IV

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

The following documents are filed as a part of this report:

Financial Statements (see Item 8):

Statements of Earnings, Years ended December 31, 1984, 1983 and 1982

Balance Sheets, December 31, 1984 and 1983

Statements of Capitalization, December 31, 1984 and 1983

Notes to Statements of Capitalization

Statements of Changes in Financial Position, Years ended December 31, 1984, 1983 and 1982

Statements of Changes in Common Stock Equity, Years ended December 31, 1984, 1983 and 1982

Notes to Financial Statements

Report of Independent Certified Public Accountants

Financial Statement Schedules

Schedule V — Utility Plant, Years ended December 31, 1984, 1983 and 1982

Schedule VI — Accumulated Provision for Depreciation, Years ended December 31, 1984, 1983, and 1982

Schedule VIII — Valuation and Qualifying Accounts, Years ended December 31, 1984, 1983 and 1982

Report of Independent Certified Public Accountants on Financial Statement Schedules

All other schedules are omitted as the required information is not applicable or is included in the financial statements or related notes.

Exhibits

The exhibits which are filed with this Form 10-K or which are incorporated herein by reference are set forth in the Exhibit Index which appears in Part IV of this report beginning at page 59.

Reports on Form 8-K

No Current Reports on Form 8-K were filed during the fourth quarter of 1984.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SCHEDULE V — UTILITY PLANT

Years Ended December 31, 1984, 1983 and 1982

Classification	Balance At Beginning of Period	Additions At Cost	Retirements	Other Changes-Add (Deduct)	Balance at End of Period
			(Thousands of Dollars)		
Year Ended December 31, 1984					
Intangibles	$ 45	$ —	$ —	$ —	$ 45
Generating Plant — Steam	200,322	27,580	1,486	18	226,434
Generating Plant — Hydro	30,257	541	7	—	30,791
Generating Plant — Other	8,411	—	—	—	8,411
Transmission	151,607	1,289	317	(168)	152,411
Distribution	214,277	17,331	2,860	(2)	228,746
General	32,874	2,894	549	89	35,308
Plant Held for Future Use	1,895	—	35	80	1,940
Unfinished Construction					
In Progress	1,033,831	271,047	—	(43)	1,304,804
Suspended	285,739	10,631	—	—	296,401
Nuclear Fuel					
In Progress	61,251	11,671	—	11,829	84,751
Suspended	17,313	—	—	(11,814)	5 499
Total	$2,037,822	$342,984	$5,254	$ (11)	$2,375,541
Year Ended December 31, 1983					
Intangibles	$ 45	$ —	$ —	$ —	$ 45
Generating Plant — Steam	197,414	7,039	3,338	(793)	200,322
Generating Plant — Hydro	23,544	6,753	45	5	30,257
Generating Plant — Other	8,408	3	—	—	8,411
Transmission	133,496	18,268	257	100	151,607
Distribution	201,484	15,776	2,332	(651)	214,277
General	27,119	7,545	1,790	—	32,874
Plant Held for Future Use	1,944	—	—	(49)	1,895
Unfinished Construction	961,350	358,220	—	—	1,319,570
Nuclear Fuel	66,259	12,305	—	—	78,564
Total	$1,621,063	$425,909	$7,762	$ (1,388)	$2,037,822
Year Ended December 31, 1982					
Intangibles	$ 45	$ —	$ —	$ —	$ 45
Generating Plant — Steam	189,077	9,301	964	—	197,414
Generating Plant — Hydro	22,861	837	154	—	23,544
Generating Plant — Other	8,409	—	1	—	8,408
Transmission	125,008	9,035	230	(317)	133,496
Distribution	192,426	11,134	2,171	95	201,484
General	23,561	4,252	694	—	27,119
Plant Held for Future Use	1,684	(57)	—	317	1,944
Unfinished Construction	716,531	259,623	—	(14,804)	961,350
Nuclear Fuel	55,995	10,843	—	(579)	66,259
Total	$1,335,597	$304,968	$4,214	$(15,288)	$1,621,063

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SCHEDULE VI — ACCUMULATED PROVISION FOR DEPRECIATION

Years Ended December 31, 1984, 1983 and 1982

Description	Balance At Beginning of Period	Additions Charged to Costs and Expenses	Retirements	Other Changes — Add (Deduct)	Balance at End of Period
			(Thousands of Dollars)		
Accumulated Provision for Depreciation of Electric Plant:					
1984	$201,044	$22,728	$5,254	$ 837 (A)	$219,355
1983	188,697	21,016	7,734	(935)(A)	201,044
1982	173,695	19,558	4,201	(355)(A)	188,697

	1984	1983	1982
(A) Represents:			
Depreciation charged to automotive clearing	$1,006	$ 1,006	$ 906
Depreciation on plant units acquired	2	2	3
Depreciation charged to construction	261	163	51
Net salvage	(432)	(1,135)	(1,352)
Non-operating reserve transfer	—	(754)	—
Plant sold	—	(217)	37
	$ 837	$ (935)	$ (355)

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 1984, 1983 and 1982

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(Thousands of Dollars)				
Reserves Deducted From Related Assets:					
Provision for Uncollectible Accounts					
1984	$ 875	$1,273	$ —	$1,189(A)	$ 959
1983	510	1,400	—	1,035(A)	875
1982	330	1,695	—	1,515(A)	510
Accumulated Provision for Depreciation of Non-Operating Property					
1984	$1,369	$ —	$ —	$ 773(E)	$ 596
1983	944	26	754(B)	355(E)	1,369
1982	947	22	—	25(E)	944
Reserve Included Under "Deferred Credits — Other":					
Reserve for Injuries and Damages					
1984	$ 630	$ 200	$ —	$ 469(D)	$ 361
1983	616	480	—	466(D)	630
1982	441	680	178(C)	683(D)	616

(A) Accounts written off, net of recoveries.

(B) Non-operating reserve transferred to operating.

(C) Charged principally to construction and retirement accounts.

(D) Losses charged to reserve.

(E) Sale of non-operating property.

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

ON FINANCIAL STATEMENT SCHEDULES

The Board of Directors
Public Service Company of New Hampshire

Under date of February 11, 1985, we reported on the balance sheets and statements of capitalization of Public Service Company of New Hampshire as of December 31, 1984 and 1983, and the related statements of earnings, changes in financial position, and changes in common stock equity for each of the years in the three-year period ended December 31, 1984. In connection with our examinations of the aforementioned financial statements, we also examined the related financial statement schedules as listed in the index under Item 14.

In our opinion, subject to the effects on the 1984 and 1983 schedules of such adjustments, if any, as might have been required had the outcome of (1) the uncertainty about the recoverability and classification of recorded asset amounts and the amounts and classification of liabilities, referred to in the second paragraph of our report on page 51 of this Form 10-K, and (2) the uncertainty about the recovery of Unit 2 costs, referred to in the third paragraph of our report on page 51 of this Form 10-K, been known, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

Peat, Marwick, Mitchell & Co.

Boston, Massachusetts
February 11, 1985

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.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By R. J. HARRISON

R. J. Harrison, President

Date: February 14, 1985

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
R. J. HARRISON R. J. Harrison (Principal Executive Officer)	President and Chief Executive Officer; Director	February 14, 1985
C. E. BAYLESS C. E. Bayless (Principal Financial Officer)	Financial Vice President	February 14, 1985
W. T. FRAIN, JR. W. T. Frain, Jr. (Principal Accounting Officer)	Vice President	February 14, 1985
HILARY P. CLEVELAND Hilary P. Cleveland	Director	February 14, 1985
George A. Dorr, Jr.	Director	February , 1985
JOHN C. DUFFETT John C. Duffett	Director	February 14, 1985
Philip S. Dunlap	Director	February , 1985
PRISCILLA K. FRECHETTE Priscilla K. Frechette	Director	February 14, 1985
PHILIP B. RYAN Philip B. Ryan	Director	February 14, 1985
William J. Scharffenberger	Director	February , 1985
JOHN T. SCHIFFMAN John T. Schiffman	Director	February 14, 1985
WILLIAM M. SCRANTON William M. Scranton	Director	February 14, 1985
EDWARD M. SHAPIRO Edward M. Shapiro	Director	February 14, 1985
WILLIAM C. TALLMAN William C. Tallman	Director	February 14, 1985
Hugh C. Tuttle	Director	February , 1985

EXHIBIT INDEX

The following designated exhibits are, as indicated below, either filed herewith or have heretofore been filed with the Securities and Exchange Commission under the Securities Act of 1933, the Securities Exchange Act of 1934 or the Public Utility Holding Company Act of 1935 and are referred to and incorporated herein by reference to such filings.

		Exhibit	SEC Docket	Form 10-K Page Nos.
Exhibit 3.	***Articles of Incorporation and by-laws***			
Incorporated herein by reference:				
3.1.	Articles of Agreement, as amended.	4.1	2-86798	
Filed herewith:				
3.2.	By-laws, as amended.			
Exhibit 4.	***Instruments defining the rights of security holders, including indentures***			
Incorporated herein by reference:				
4.1.	General and Refunding Mortgage Indenture dated as of August 15, 1978 between the Company and New England Merchants National Bank, Trustee.	2.32	2-62856	
4.1.1.	First Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of September 15, 1979.	2.32	2-65427	
4.1.2.	Second Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of January 15, 1980.	2.5	2-66334	
4.1.3.	Third Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of December 1, 1980.	2.3.3	2-69947	
4.1.4.	Fourth Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of June 1, 1982.	4.1.4	2-77577	
4.1.5.	Fifth Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of June 19, 1984.	4.1.5	2-92102	
4.1.6.	Sixth Supplemental Indenture to the General and Refunding Mortgage Indenture dated as of August 15, 1984.	4.1.6	2-92102	
4.2.	First Mortgage dated as of January 1, 1943 between the Company and Old Colony Trust Company, Trustee.	4.4	2-81165	
4.2.1.	First Supplemental Indenture to the Company's First Mortgage dated as of December 1, 1943.	A-1a	70-684	
4.2.2.	Second Supplemental Indenture to the Company's First Mortgage dated as of June 1, 1947.	7.3	2-7066	
4.2.3.	Third Supplemental Indenture dated as of January 1, 1948.	7.4	2-7324	
4.2.4.	Fourth Supplemental Indenture dated as of October 1, 1948.	7.5	2-7658	

		Exhibit	SEC Docket	Form 10-K Page Nos.
4.2.5.	Fifth Supplemental Indenture dated as of June 1, 1949.	7.6	2-7985	
4.2.6.	Sixth Supplemental Indenture dated as of June 1, 1951.	7.7	2-8969	
4.2.7.	Seventh Supplemental Indenture dated as of September 1, 1953.	4.9	2-10426	
4.2.8.	Eighth Supplemental Indenture dated as of November 1, 1954.	4.4.8	2-81165	
4.2.9.	Ninth Supplemental Indenture dated as of June 1, 1956.	4.4.9	2-81165	
4.2.10.	Tenth Supplemental Indenture dated as of October 1, 1957.	2.12	2-15260	
4.2.11.	Eleventh Supplemental Indenture dated as of July 1, 1959.	2.13	2-17162	
4.2.12.	Twelfth Supplemental Indenture dated as of November 1, 1960.	2.14	2-20451	
4.2.13.	Thirteenth Supplemental Indenture dated as of July 1, 1962.	4.4.13	2-81165	
4.2.14.	Fourteenth Supplemental Indenture dated as of January 1, 1966.	4.4.14	2-81165	
4.2.15.	Fifteenth Supplemental Indenture dated as of October 1, 1966.	4.4.15	2-81165	
4.2.16.	Sixteenth Supplemental Indenture dated as of June 1, 1967.	4.4.16	2-81165	
4.2.17.	Seventeenth Supplemental Indenture dated as of November 1, 1968.	2.19	2-30554	
4.2.18.	Eighteenth Supplemental Indenture dated as of November 1, 1970.	4.20	2-38646	
4.2.19.	Nineteenth Supplemental Indenture dated as of June 15, 1972.	2.22	2-50198	
4.2.20.	Twentieth Supplemental Indenture dated as of March 1, 1974.	2.23	2-50198	
4.2.21.	Twenty-First Supplemental Indenture dated as of October 15, 1974.	2.24	2-51999	
4.2.22.	Twenty-Second Supplemental Indenture dated as of December 1, 1974.	2.25	2-54646	
4.2.23.	Twenty-Third Supplemental Indenture dated as of March 1, 1975.	2.26	2-54646	
4.2.24.	Twenty-Fourth Supplemental Indenture dated as of October 15, 1975.	2.27	2-57289	
4.2.25.	Twenty-Fifth Supplemental Indenture dated as of October 15, 1976.	2.28	2-59516	
4.2.26.	Twenty-Sixth Supplemental Indenture dated as of November 1, 1976.	2.29	2-59516	
4.2.27.	Twenty-Seventh Supplemental Indenture dated as of May 1, 1978.	2.30	2-61924	
4.2.28.	Twenty-Eighth Supplemental Indenture dated as of August 15, 1978.	2.31	2-62856	
4.2.29.	Twenty-Ninth Supplemental Indenture dated as of September 15, 1979.	2.33	2-65427	
4.2.30.	Thirtieth Supplemental Indenture dated as of January 15, 1980.	2.4.30	2-66492	

		Exhibit	SEC Docket	Form 10-K Page Nos.
4.2.31.	Thirty-First Supplemental Indenture dated as of December 1, 1980.	2.4.31	2-69947	
4.2.32.	Thirty-Second Supplemental Indenture dated as of June 1, 1982.	4.2.32	2-77577	
4.3.	Indenture dated as of August 15, 1981 among PSNH International Finance N.V. and PSNH International Finance B.V., as Issuers; the Company, as Guarantor; and Morgan Guaranty Trust Company of New York, as Trustee.	4.3	Annual Report 1-6392 for 1981	
4.4.	Promissory Note dated August 15, 1981, from the Company to PSNH International Finance N.V.	4.4	Annual Report 1-6392 for 1981	
4.5.	Promissory Note dated August 15, 1981, from the Company to PSNH International Finance B.V.	4.5	Annual Report 1-6392 for 1981	
4.6.	Indenture dated as of October 1, 1982 between the Company and Manufacturers Hanover Trust Company, Trustee, relating to the 15¾% Debentures due 1988.	4.3	2-79411	
4.7.	Indenture dated as of February 1, 1983 between the Company and Manufacturers Hanover Trust Company, Trustee, relating to the 14⅜% Debentures due 1991.	4.6	2-81367	
4.8.	Indenture dated as of November 1, 1983 between the Company and Manufacturers Hanover Trust Company, Trustee, relating to the 15% Debentures due 2003.		Registration Statement on Form 8-A relating to 15% Debentures due 2003 (File No. 1-6392)	
4.9.	Trust Indenture dated as of December 1, 1983 between the New Hampshire Industrial Development Authority and State Street Bank and Trust Company, Trustee, relating to the Pollution Control Revenue Bonds, 1983 Series A (Public Service Company of New Hampshire Project).	4.9	Annual Report 1-6392 for 1983	
4.9.1.	Loan Agreement dated as of December 1, 1983 between the Company and the New Hampshire Industrial Development Authority relating to loans to the Company of the proceeds of the bonds issued under Exhibit 4.9.	4.9.1	Annual Report 1-6392 for 1983	
4.10.	Trust Indenture dated as of October 15, 1984 between the Company and Midlantic National Bank, Trustee, relating to the 17½% Debentures due 2004.	4.10	2-92102	
4.12.	Warrant Agreement dated as of October 15, 1984 between the Company and The First National Bank of Boston, relating to Warrants to purchase 18,375,000 shares of Common Stock.	4.12	2-92102	

		Exhibit	SEC Docket	Form 10-K Page Nos.
Exhibit 10.	***Material Contracts***			
Incorporated herein by reference:				
10.1.	Nuclear Material Lease and Security Agreement dated as of June 15, 1983 between the Company and PruLease, Inc.	10.2	Annual Report 1-6392 for 1983	
10.1.1.	Amendment No. 1 to Exhibit 10.1 dated as of August 23, 1984.	10.1.1	2-92102	
10.2.	Form of New England Power Pool Agreement dated as of September 1, 1971 as amended to November 15, 1983.	10.3	Annual Report 1-6392 for 1983	
10.3.	Agreement dated October 13, 1972 for Joint Ownership, Construction and Operation of Pilgrim Unit No. 2 among Boston Edison Company and other utilities including the Company.	5.3(d)	2-45990	
10.3.1.	Amendments Nos. 1 and 2 to Exhibit 10.3 dated September 20, 1973 and September 15, 1974, respectively.	5.14	2-51999	
10.3.2.	Amendment No. 3 to Exhibit 10.3 dated December 1, 1974.	13-45	2-54449	
10.3.3.	Amendments Nos. 4 and 5 to Exhibit 10.3 dated February 15, 1975 and April 30, 1975, respectively.	13-52-A 13-52-B	2-53819	
10.3.4.	Amendment No. 6 to Exhibit 10.3 dated June 30, 1975.	13-45(a)	2-54449	
10.3.5.	Amendment No. 7 to Exhibit 10.3 dated November 30, 1975.	5.9(f)	2-55748	
10.3.6.	Addendum to Exhibit 10.3 as of October 1, 1976.	10.1	Annual Report 1-2301-2 for 1976	
10.4.	Agreement for Sharing Costs Associated with Pilgrim Unit No. 2 Transmission dated October 13, 1972 among Boston Edison Company and other utilities including the Company.	5.3(e)	2-45990	
10.4.1.	Addendum to Exhibit 10.4 as of January 17, 1975.	1.5.1	Annual Report 1-2301-2 for 1975	
10.4.2.	Addendum to Exhibit 10.4 dated as of October 1, 1976.	10.2	Annual Report 1-2301-2 for 1976	
10.5.	Agreement dated as of May 1, 1973 for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units among the Company and other utilities.	13-57	2-48966	
10.5.1.	Amendments to Exhibit 10.5 dated May 24, 1974, June 21, 1974 and September 25, 1974.	5.15	2-51999	
10.5.2.	Amendments to Exhibit 10.5 dated October 25, 1974 and January 31, 1975.	5.23	2-54646	
10.5.3.	Sixth Amendment to Exhibit 10.5 as of April 18, 1979.	5.4.3	2-64294	
10.5.4.	Seventh Amendment to Exhibit 10.5 dated as of April 18, 1979.	5.4.4	2-64294	
10.5.5.	Eighth Amendment to Exhibit 10.5 dated as of April 25, 1979.	5.4.5	2-64815	

		Exhibit	SEC Docket	Form 10-K Page Nos.
10.5.6.	Ninth Amendment to Exhibit 10.5 dated as of June 8, 1979.	5.4.6	2-64815	
10.5.7.	Tenth Amendment to Exhibit 10.5 dated as of October 10, 1979.	5.4.2	2-66334	
10.5.8.	Eleventh Amendment to Exhibit 10.5 dated as of December 15, 1979.	5.4.8	2-66492	
10.5.9.	Twelfth Amendment to Exhibit 10.5 dated as of June 16, 1980.	5.4.9	2-68168	
10.5.10.	Thirteenth Amendment to Exhibit 10.5 dated as of December 31, 1980.	10.6.10	2-70579	
10.5.11.	Fourteenth Amendment to Exhibit 10.5 dated as of June 1, 1982.	10.6.11	Annual Report 1-6392 for 1982	
10.5.12.	Fifteenth Amendment to Exhibit 10.5 dated as of April 27, 1984.	10.5.12	2-92102	
10.5.13.	Sixteenth Amendment to Exhibit 10.5 dated as of June 23, 1984.	10.5.13	2-92102	
10.5.14.	Agreement for Seabrook Project Disbursing Agent.	10.5.14	2-92102	
10.6.	Transmission Support Agreement dated as of May 1, 1973 among the Company and other utilities with respect to New Hampshire nuclear units.	13-58	2-48966	
10.7.	Sharing Agreement — 1979 Connecticut Nuclear Unit dated September 1, 1973 to which the Company is a party.	6.43	2-50142	
10.7.1.	Amendment to Exhibit 10.7 dated August 1, 1974.	5.45	2-52392	
10.7.2.	Amendment to Exhibit 10.7 dated December 15, 1975.	7.47	2-60806	
10.8.	Agreement executed on January 23, 1973 for the design and furnishing of the nuclear steam supply systems for the Company's Seabrook plant between the Company and Westinghouse Electric Corporation.	C	Annual Report 1-6392 for 1972	
10.9.	Agreement dated November 1, 1974 for Joint Ownership, Construction and Operation of William F. Wyman Unit No. 4 among Central Maine Power Company and other utilities including the Company.	5.16	2-52900	
10.9.1.	Amendment to Exhibit 10.9 dated June 30, 1975.	5.48	2-55458	
10.9.2.	Amendment to Exhibit 10.9 dated as of August 16, 1976.	5.19	2-58251	
10.9.3.	Amendment to Exhibit 10.9 dated as of December 31, 1978.			
10.10.	Transmission Support Agreement dated November 1, 1974 among Central Maine Power Company and other utilities including the Company.	13-57	2-54449	

		Exhibit	SEC Docket	Form 10-K Page Nos.
10.11.	Transmission Support Agreement dated August 9, 1974 between the Connecticut Light and Power Company and other utilities including the Company.	5.24	2-54646	
10.12.	Pension Plan of Public Service Company of New Hampshire, amended effective as of January 1, 1981.	10.14	Annual Report 1-6392 for 1981	
10.12.1.	First Amendment to Exhibit 10.12.	10.12.1	2-92102	
10.13.	Term Loan Agreement dated as of December 28, 1977, among the Company and seven Banks.	F	Annual Report 1-6392 for 1977	
10.13.1.	Amendment No. 1 to Exhibit 10.13 dated as of December 26, 1978.	5.16.1	2-62856	
10.13.2.	Amendment No. 2 to Exhibit 10.13 dated as of December 28, 1979.	5.15.2	2-66334	
10.13.3.	Amendment No. 3 to Exhibit 10.13 dated as of December 1, 1980.	10.17.3	2-70579	
10.13.4.	Amendment No. 4 to Exhibit 10.13 dated as of December 30, 1981.	10.16.4	Annual Report 1-6392 for 1981	
10.13.5.	Amendment No. 5 to Exhibit 10.13 dated as of January 7, 1983.	10.16.5	Annual Report 1-6392 for 1982	
10.13.6.	Amendment No. 6 to Exhibit 10.13 dated as of February 4, 1983.	10.16.6	Annual Report 1-6392 for 1982	
10.13.7.	Amendment No. 7 to Exhibit 10.13 dated as of March 7, 1983.	10.16.4	Annual Report 1-6392 for 1982	
10.13.8.	Amendment No. 8 to Exhibit 10.13 dated as of April 11, 1983.	10.15.8	Annual Report 1-6392 for 1983	
10.13.9.	Amendment No. 9 to Exhibit 10.13 dated as of April 25, 1983.	10.15.9	Annual Report 1-6392 for 1983	
10.13.10.	Amendment No. 10 to Exhibit 10.13 dated as of June 22, 1984.	10.13.10	2-92102	
10.13.11.	Amendment and Restatement of Exhibit 10.13 dated as of August 23, 1984.	10.13.10	2-92102	
10.14.	Eurodollar Loan Agreement dated August 25, 1980.	5.16	2-69370	
10.14.1.	Amendment and Restatement of Exhibit 10.14 dated as of December 8, 1981.	10.17.1	Annual Report 1-6392 for 1981	
10.14.2.	Amendment No. 1 to Exhibit 10.14.1 dated as of August 23, 1982.	10.16.2	Annual Report 1-6392 for 1982	
10.14.3.	Agreement dated as of August 23, 1984 amending and restated Exhibit 10.14	10.14.3	2-92102	
10.15.	Employee Stock Ownership Plan and Trust.	10.19	2-70579	
10.16.	Agreement dated as of June 20, 1984 between the Company and United Engineers & Constructors, Inc.	10.16	2-92102	

		Exhibit	SEC Docket	Form 10-K Page Nos.
10.17.	Secured Revolving Credit Agreement dated as of August 23, 1984 among the Company, seven banks and PruLease, Inc.	10.17	2-92102	
10.17.1.	Security Agreement dated as of August 23, 1984 among the Company, seven banks and Prudential Interfunding Corp.	10.17.1	2-92102	

Exhibit 11. ***Statement re computation of per share earnings***

Filed herewith:

11.1. Calculation of Earnings per Common and Common Equivalent Share.

Exhibit 12. ***Statement re computation of ratios***

Filed herewith:

12.1. Calculation of Ratios of Earnings to Fixed Charges.

EXHIBIT 11.1

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

CALCULATION OF EARNINGS PER COMMON AND COMMON EQUIVALENT SHARE

	For the Year Ended December 31,		
	1984	1983	1982
	(Thousands except Per Share Amounts)		
Reconciliation of earnings available for common to amount used in calculation			
Earnings Available for Common	$115,617	$118,662	$69,470
Add:			
Interest on long-term debt, net of tax effect on application of assumed proceeds from the exercise of warrants in excess of 20% limitation	633	—	—
Estimated increase in allowance for funds used during construction	160	—	—
Adjusted Earnings Available for Common	$116,410	$118,662	$69,470
Reconciliation of weighted average number of shares outstanding to amount used in pro forma calculation			
Weighted average number of shares outstanding	37,162	34,026	25,458
Add:			
Shares issuable from the assumed exercise of warrants in excess of 20% limitation (a)	758	—	—
Adjusted	37,920	34,026	25,458
Earnings per Common and Common Equivalent Share	$3.07	$3.49	$2.73

(a) 18,375,000 shares from the assumed exercise of warrants less 20% limitation of assumed repurchases (7,438,213) weighted for the period of time since the issuance of warrants.

EXHIBIT 12.1

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

CALCULATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	1984	1983	1982	1981	1980
	(Thousands of Dollars)				
Net Income	$156,600	$151,658	$ 91,623	$ 77,187	$ 59,847
Add: Provision for Taxes Based on Income	6,940	4,783	4,764	4,688	5,526
Taxes Applicable to AFUDC	34,177	28,282	25,596	24,333	17,093
Fixed Charges	128,858	93,209	81,667	77,459	62,681
	326,575	277,932	203,650	183,667	145,147
Deduct: Undistributed Earnings of Affiliated Companies	(722)	2,096	2,313	790	(48)
Earnings Available for Fixed Charges	$327,297	$275,836	$201,337	$182,877	$145,195
Fixed Charges					
Interest on Long-Term Debt	$105,482	$ 85,649	$ 61,169	$ 50,229	$ 39,711
Other Interest	21,920	6,122	19,015	25,989	21,847
Interest Component of Rental Charges	1,456	1,438	1,483	1,241	1,123
Total Fixed Charges	$128,858	$ 93,209	$ 81,667	$ 77,459	$ 62,681
Ratios	2.54	2.96	2.47	2.36	2.32

General Information

Annual Meeting of Shareowners

All shareowners are urged to attend the Annual Meeting to be held on Thursday, March 21, 1985, at 9:30 a.m. EST, at the Sheraton-Tara Hotel Ballroom, Nashua, NH (Route 3 — Everett Turnpike, Exit 1 to Tara Boulevard).

Description of Business

Public Service Company of New Hampshire is the largest electric utility in New Hampshire, supplying electricity to approximately three-quarters of the state's population. The Company distributes and sells electricity at retail in approximately 200 cities and towns in the state. The Company also sells electricity at wholesale to seven other utilities.

Annual Report and Statistical Supplement

This 1984 Annual Report has been approved by the Board of Directors. The 1984 Statistical Supplement, containing corporate statistics for the last 10 years, will be available after March 21, 1985. If you would like a copy, or have questions about the Annual Report or the Company, please write to Russell A. Winslow, Secretary, Public Service of New Hampshire, P.O. Box 330, Manchester, NH 03105.

Stock Exchange Listing

Shares of $5 par value common stock and $25 par value preferred stock are listed on the New York Stock Exchange. The Company's symbol on the exchange is PNH.

Shareowner Information

Shareowner inquiries regarding change of address, stock transfer requirements, lost or stolen certificates, or other account information should be directed to the Transfer Agent as follows:

The First National Bank of Boston
P.O. Box 644
Boston, MA 02102

PSNH
Public Service of New Hampshire

1000 Elm Street, Manchester, New Hampshire 03105

Form Approved
OMB No. 1902-0021
(Expires 9/30/87)

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
VERMONT ELECTRIC GENERATION & TRANSMISSION COOPERATIVE, INC.	Dec. 31, 19 84

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 public 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 (Statistics of Privately Owned Electric Utilities in the United States) published by the Energy Information Administration.

II. Who Must Submit

Each Major public 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 the previous calendar year, 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 gross interchange out,
(4) 500 megawatt hours of wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit an original and six (6) copies of this form to:

U.S. Department of Energy
Energy Information Administration EI 541
Mail Station: BG-094
Forrestal Building
Washington, D.C.

Retain one copy of this report for your files.

(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 analyst, or industry association. (Do not include monthly and quarterly reports. If reports to stockholders are not prepared, enter "NA" in column (d) on Page 4, the List of Schedules.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol St., N.E.
Room 601-RB
Washington, D.C. 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:

(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.)

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

When accompanying this form, insert the letter or report immediately following the cover sheet.

GENERAL INFORMATION (Continued)

III. What and Where to Submit (Continued)

(c) (Continued)

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 statement of for the year ended on which we have reported separately under date of we have also reviewed schedules of form 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:

U.S. Department of Energy
National Energy Information Center
Energy Information Administration
Washington, D.C. 20585
(202) 252-8800

IV. When to Submit:

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

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18CFR 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 years 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, either

(a) Enter the words "Not Applicable" on the particular page(s), or

(b) 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. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. The copies, however, may be carbon copies or other similar means of reproduction provided the impressions are clear and readable.

of Re

GENERAL INSTRUCTIONS (Continued)

VI. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" at the top of each page is applicable only to resubmissions (see VIII. below).

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the Identification and Attestation page, page 1. Mail dated resubmissions to:

Chief Accountant
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Room 601-RB
Washington, D.C. 20426

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8½ by 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and the page number supplemented.

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

XI. 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.

XII. Respondents may submit computer printed schedules (reduced to 8½ by 11) instead of the preprinted schedules if they are in substantially the same format.

DEFINITIONS

II. 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.

III. Respondent — The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

(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 shall 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 on the business of developing, transmitting, utilizing, 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, a 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 as 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;

EXCERPTS FROM THE LAW (Continued)

"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 by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and form in which such reports shall 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, amend, 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 or 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 OTHERS

IDENTIFICATION		
01 Exact Legal Name of Respondent Vermont Electric Generation & Transmission Cooperative, Inc.		02 Year of Report Dec. 31, 1984
03 Previous Name and Date of Change *(If name changed during year)*		
04 Address of Principal Business Office at End of Year *(Street, City, State, Zip Code)* School Street, Johnson, Vermont 05656		
05 Name of Contact Person Jerry L. Bucholz	06 Title of Contact Person Controller	
07 Address of Contact Person *(Street, City, State, Zip Code)* School Street, Johnson, Vermont 05656		
08 Telephone of Contact Person, *Including Area Code* (802) 635-2331	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 4/15/85

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 Jerry L. Bucholz	03 Signature Jerry L. Bucholz	04 Date Signed *(Mo, Da, Yr)* 4/15/85
02 Title Asst. Treasurer & Controller		
Title 18, U.S.C. 1001, makes it a crime for any person 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	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Taxes Accrued, Prepaid and Charged During Year	258–259		
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		
Accumulated Deferred Investment Tax Credits	264		
Other Deferred Credits	266		
Accumulated Deferred Income Taxes–Accelerated Amortization Property	268–269		
Accumulated Deferred Income Taxes–Other Property	270–271		
Accumulated Deferred Income Taxes–Other	272–273		
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	301	12-84	
Sales of Electricity by Rate Schedules	304		
Sales for Resale	310–311		
Electric Operation and Maintenance Expenses	320–323	12-84	
Number of Electric Department Employees	323		
Purchased Power	326–327		
Interchange Power	328		
Transmission of Electricity for or by Others	332		
Miscellaneous General Expenses–Electric	333		
Depreciation and Amortization of Electric Plant	334–336		
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	337		
COMMON SECTION			
Regulatory Commission Expenses	350–351		
Research, Development and Demonstration Activities	352–353		
Distribution of Salaries and Wages	354–355		
Common Utility Plant and Expenses	356		
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401		
Monthly Peaks and Output	401		
Steam-Electric Generating Plant Statistics (Large Plants)	402–403		
Steam-Electric Generating Plant Statistics (Large Plants) Average Annual Heat Rates and Corresponding Net Kwh Output for Most Efficient Generating Units	404		
Hydroelectric Generating Plant Statistics (Large Plants)	406–407		
Pumped Storage Generating Plant Statistics (Large Plants)	408–409		
Generating Plant Statistics (Small Plants)	410		
Changes Made or Scheduled to be Made in Generating Plant Capacities	411		
Steam-Electric Generating Plants	412–413		
Hydroelectric Generating Plants	414–415		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Pumped Storage Generating Plants	416–418		
Internal-Combustion Engine and Gas-Turbine Generating Plants	420–421		
Transmission Line Statistics	422–423		
Transmission Lines Added During Year	424		
Substations	425		
Electric Distribution Meters and Line Transformers	427		
Environmental Protection Facilities	428		
Environmental Protection Expenses	429		
Footnote Data	450		
Stockholders' Reports	–		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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.

Jerry L. Bucholz
Controller
School Street, Johnson, Vermont 05656

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.

Vermont - 1979

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.

Not Applicable

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

Wholesale electric sales - Vermont

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

(1) [ ] YES ...Enter the date when such independent accountant was initially engaged: ______________.
(2) [X] NO

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of 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 beneficiaries for whom trust was maintained, and purpose of the trust.

2. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed provided the fiscal years for both the 10-K report and this report are compatible.

Vermont Electric Cooperative, Inc., is the only Class A Member of the Generation and Transmission Cooperative at December 31, 1984. As the only Class A Member, it elected five members to the Board of Trustees.

There are two Class B Members; New Hampshire Electric Cooperative, Inc., and Fox Island Electric Cooperative, Inc. Class B Members as a class can elect one member to the Board of Trustees.

There are six Class C Members; Connecticut Light and Power Company, Western Massachusetts Electric Company, Central Vermont Public Service Corporation, the Village of Johnson, the Village of Hyde Park and North Attleborough Electric Department. Class C Members as a class can elect one member to the Board of Trustees.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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.

4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

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.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
	INTENTIONALLY BLANK		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 policymaking 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 date the change in incumbency was made.

3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substituted page(s) should be the same size as this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President	J. Douglas Webb	
2			
3	1st Vice-President	Clyde Jones	
4			
5	2nd Vice-President	Robert Northrop	
6			
7	Treasurer	Marshall Washer	
8			
9	*Vice-President & Executive Mgr.	William J. Gallagher	
10			
11	*Asst. Treasurer & Controller	Jerry L. Bucholz	
12			
13	*Asst. Secretary	Nora H. Winckler	
14			
15	Secretary	Laura L. D. Howe	
16			
17	*Not a Member of the Board of Trustees, but an operating officer of the G&T.		
18			
19	No officer or employee earned a salary of $50,000 or more from the Cooperative		
20	during 1984.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)
*J. Douglas Webb, President	Fairfax, Vermont 05454
*Clyde W. Jones, 1st Vice-President	East Dover, Vermont 05341
*Robert Northrop	RD#1, Box 540, Cambridge, VT 05444
*Laura L. D. Howe, Clerk	49 Fairview, Brattleboro, VT 05301
*Marshall Washer, Treasurer	R.D.#2, Johnson, Vermont 05656
Arthur Wadleigh	R.D.#3, Box 55, Plymouth, NH 03264
Walter T. Schultheis	c/o Northeast Utilities P.O. Box 270 Hartford, Connecticut 06101

FERC FORM NO. 1 (REVISED 12-81)   Page 106

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights 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 for 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 rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any 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 general public where the options, warrants, or rights were issued on a prorata basis.

1. Give 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 the end of year for election of directors of the respondent and number of such votes cast by proxy Total: By proxy:	3. Give the date and place of such meeting:

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				
5	TOTAL number of security holders				
6	TOTAL votes of security holders listed below				
7					
8	This is a rural electric generation and transmission				
9	corporation (cooperative).				
10					
11	Class A members have 5 votes (for all members within this class).				
12	Class B members have 1 vote (for all members within this class).				
13	Class C members have 1 vote (for all members within this class).				
14					
15					
16					
17					
18					

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 therefor 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 conditions. 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 attached to this page.

1. Not Applicable
2. None
3. None
4. None
5. None
6. None
7. None
8. None
9. None
10. In January 1984, the Vermont Electric Generation & Transmission Cooperative, Inc. ("VEG&T") purchased 0.41259% joint ownership in the Seabrook Nuclear generation project, 0.20% of the Millstone Nuclear Unit No. 3 Project and 0.20% of the Pilgrim Nuclear Unit No. 2 Project with associated transmission and nuclear fuel from the Vermont Electric Cooperative, Inc. ("VEC") for a total of $19,424,203.40. The Cooperative assumed $13,970,173.32 in REA insured long-term debt, assumed $3,977,518.42 in REA Guaranteed long-term debt and $1,476,511.66 in cash. In addition, the VEG&T assumed long-term loan commitments for construction costs of the projects in the amount of $1,776,000 REA insured loan and $5,919,000 remaining on an REA guaranteed loan.
11. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

IMPORTANT CHANGES DURING THE YEAR (Continued)

INTENTIONALLY BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) X An Original (2) ☐ A Resubmission		Dec. 31, 1984

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	32,640	32,640
3	Construction Work in Progress (107)	200	8,929,615	39,059,369
4	TOTAL Utility Plant *(Enter Total of lines 2 and 3)*		8,962,255	39,092,009
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200	2,900	4,948
6	Net Utility Plant *(Enter Total of line 4 less 5)*	—	8,959,355	39,087,061
7	Nuclear Fuel (120.1-120.4, 120.6)	201	121,499	1,162,819
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	201		
9	Net Nuclear Fuel *(Enter Total of line 7 less 8)*	—	121,499	1,162,819
10	Net Utility Plant *(Enter Total of lines 6 and 9)*	—	9,080,854	40,249,880
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	214		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	215		
15	(Less) Accum. Prov. for Depr. and Amort. (122)	215		
16	Investments in Associated Companies (123)	216	1,010	18,177
17	Investment in Subsidiary Companies (123.1)	217		18,278
18	(For Cost of Account 123.1, See Footnote Page 217, line 23)	—		
19	Other Investments (124)			
20	Special Funds (125-128)	—		
21	TOTAL Other Property and Investments *(Total of lines 14 thru 20)*	—	1,010	36,455
22	CURRENT AND ACCRUED ASSETS			
23	Cash (131)	—	23,306	18,292
24	Special Deposits (132-134)	—		
25	Working Funds (135)	—		
26	Temporary Cash Investments (136)	216	377,457	4,494
27	Notes Receivable (141)	—		
28	Customer Accounts Receivable (142)	—	214,869	276,057
29	Other Accounts Receivable (143)	—		
30	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	—		
31	Notes Receivable from Associated Companies (145)	—		
32	Accounts Receivable from Assoc. Companies (146)	—		
33	Fuel Stock (151)	—		
34	Fuel Stock Expense Undistributed (152)	—		
35	Residuals (Elec) and Extracted Products (Gas) (153)	—		
36	Plant Material and Operating Supplies (154)	—		
37	Merchandise (155)	—		
38	Other Material and Supplies (156)	—		
39	Nuclear Materials Held for Sale (157)	201		
40	Stores Expenses Undistributed (163)	—		
41	Gas Stored Underground — Current (164.1)	214		
42	Liquefied Natural Gas Stored (164.2)	214		
43	Liquefied Natural Gas Held for Processing (164.3)	214		
44	Prepayments (165)	220	2,103	7,887
45	Advances for Gas Explor., Devel. and Prod. (166)	219		
46	Other Advances for Gas (167)	219		
47	Interest and Dividends Receivable (171)	—		
48	Rents Receivable (172)	—		
49	Accrued Utility Revenues (173)	—		
50	Miscellaneous Current and Accrued Assets (174)			
51	TOTAL Current and Accrued Assets *(Enter Total of lines 23 thru 50)*		617,735	306,730

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

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)
52	DEFERRED DEBITS			
53	Unamortized Debt Expense (181)	–	17,847	39,950
54	Extraordinary Property Losses (182.1)	220	--	1,023,371
55	Unrecovered Plant and Regulatory Study Costs (182.2)	220		
56	Prelim. Survey and Investigation Charges (Electric) (183)	–	93,102	49,875
57	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	–		
58	Clearing Accounts (184)	–		
59	Temporary Facilities (185)	–		
60	Miscellaneous Deferred Debits (186)	223	310,977	207,723
61	Def. Losses from Disposition of Utility Plt. (187)	–		
62	Research, Devel. and Demonstration Expend. (188)	352–353		
63	Unamortized Loss on Reacquired Debt (189)	–		
64	Accumulated Deferred Income Taxes (190)	224		
65	Unrecovered Purchased Gas Costs (191)	–		
66	Unrecovered Incremental Gas Costs (192.1)	–		
67	Unrecovered Incremental Surcharges (192.2)	–		
68	TOTAL Deferred Debits *(Enter Total of lines 53 thru 67)*		421,926	1,320,919
69	TOTAL Assets and other Debits *(Enter Total of lines 10, 11, 12, 21, 51, and 68)*		10,121,525	41,913,984

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Omit Cents: Balance at Beginning of Year (c)	Omit Cents: Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Memberships	250	45	40
3		250		
4		251		
5		251		
6		251		
7	Other Margins and Equity	252	6,005	30,188
8	Installments Received on Capital Stock (212)	251		
9	(Less) Discount on Capital Stock (213)	253		
10	(Less) Capital Stock Expense (214)	253		
11	Retained Earnings (215, 215.1, 216)	118-119		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250		
14	TOTAL Proprietary Capital *(Enter Total of lines 2 thru 13)*	–	6,050	30,228
15	LONG-TERM DEBT			
16	Bonds (221)	256		
17	(Less) Reacquired Bonds (222)	256		
18	Advances from Associated Companies (223)	256		
19	Other Long-Term Debt (224)	256	5,028,399	34,883,454
20	Unamortized Premium on Long-Term Debt (225)	–		
21	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)	–		
22	TOTAL Long-Term Debt *(Enter Total of lines 16 thru 21)*	–	5,028,399	34,883,454
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases - Noncurrent (227)	–		
25	Accumulated Provision for Property Insurance (228.1)	–		
26	Accumulated Provision for Injuries and Damages (228.2)	–		
27	Accumulated Provision for Pensions and Benefits (228.3)	–		
28	Accumulated Miscellaneous Operating Provisions (228.4)	–		
29	Accumulated Provision for Rate Refunds (229)	–		
30	TOTAL Other Noncurrent Liabilities *(Enter Total of lines 24 thru 29)*			
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	–	3,773,299	4,671,643
33	Accounts Payable (232)	–	1,105,680	1,988,697
34	Notes Payable to Associated Companies (233)	–		
35	Accounts Payable to Associated Companies (234)	–	20,341	318,000
36	Customer Deposits (235)	–		
37	Taxes Accrued (236)	258-259	5,068	2
38	Interest Accrued (237)	–	182,688	21,960
39	Dividends Declared (238)	–		
40	Matured Long-Term Debt (239)	–		
41	Matured Interest (240)	–		
42	Tax Collections Payable (241)	–		
43	Miscellaneous Current and Accrued Liabilities (242)	–		
44	Obligations Under Capital Leases-Current (243)	–		
45	TOTAL Current and Accrued Liabilities *(Enter Total of lines 32 thru 44)*		5,087,076	7,000,302

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

COMPARATIVE BALANCE SHEET (LIABILITIES AND CREDITS) (CONTINUED)

Line No.	Title of Account (a)	Ref. Page No. (b)	Omit Cents: Balance Beginning of Year (c)	Omit Cents: Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)			
48	Accumulated Deferred Investment Tax Credits (255)	264		
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	266		
51	Unamortized Gain on Reacquired Debt (257)	257		
52	Accumulated Deferred Income Taxes (281-283)	268-273		
53	TOTAL Deferred Credits *(Enter Total of lines 47 thru 52)*			
54				
55				
56				
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63				
64				
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66				
67				
68				
69	TOTAL Liabilities and Other Credits *(Enter Total of lines 14, 22, 30, 45 and 53)*			41,913,984

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 01 thru 20 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 page 122 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)		6,701,219	5,657,598
3	Operating Expenses			
4	Operation Expenses (401)		6,547,015	5,621,828
5	Maintenance Expenses (402)			
6	Depreciation Expense (403)			
7	Amort. & Depl. of Utility Plant (404-405)			
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		35,666	
10	Amort. of Conversion Expenses (407)			
11	Taxes Other Than Income Taxes (408.1)	258	9	14
12	Income Taxes – Federal (409.1)	258		
13	– Other (409.1)	258		
14	Provision for Deferred Inc. Taxes (410.1)	224, 268-273		
15	(Less) Provision for Deferred Income Taxes–Cr. (411.1)	224, 268-273		
16	Investment Tax Credit Adj. – Net (411.4)	264		
17	(Less) Gains from Disp. of Utility Plant (411.6)			
18	Losses from Disp. of Utility Plant (411.7)			
19	TOTAL Utility Operating Expenses *(Enter Total of lines 4 thru 18)*		6,582,690	5,621,842
20	Net Utility Operating Income *(Enter Total of line 2 less 19) (Carry forward to page 117, line 21)*		118,529	35,756

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 attached at page 122.

8. Enter on page 122 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 1 to 19, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current year (e)	Previous Year (f)	Current year (g)	Previous Year (h)	Current year (i)	Previous Year (j)	Line No.
						1
6,701,219	5,657,598					2
						3
6,547,015	5,621,828					4
						5
						6
						7
						8
35,666						9
						10
9	14					11
						12
						13
						14
						15
						16
						17
						18
6,582,690	5,621,842					19
118,529	35,756					20

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [XX] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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						
3						
4						
5						
6						
7						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	Ref. Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
21	Net Utility Operating Income *(Carried forward from page 114)*	–	118,529	35,756
22	Other Income and Deductions			
23	Other Income			
24	Nonutility Operating Income			
25	Revenues From Merchandising, Jobbing and Contract Work (415)			
26	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			
27	Revenues From Nonutility Operations (417)			
28	(Less) Expenses of Nonutility Operations (417.1)			
29	Nonoperating Rental Income (418)			
30	Equity in Earnings of Subsidiary Companies (418.1)	–		
31	Interest and Dividend Income (419)		5,637	2,457
32	Allowance for Other Funds Used During Construction (419.1)	–		
33	Miscellaneous Nonoperating Income (421)			
34	Patronage Capital - NRUCFC (424)		18,278	-0-
35	TOTAL Other Income *(Enter Total of lines 25 thru 34)*	–	23,915	2,457
36	Other Income Deductions			
37	Loss on Disposition of Property (421.2)			
38	Miscellaneous Amortization (425)	337		
39	Miscellaneous Income Deductions (426.1-426.5)	337	50	10,435
40	TOTAL Other Income Deductions *(Total of lines 37 thru 39)*	–	50	10,435
41	Taxes Applic. to Other Income and Deductions			
42	Taxes Other Than Income Taxes (408.2)	258		
43	Income Taxes—Federal (409.2)	258		
44	Income Taxes—Other (409.2)	258		
45	Provision for Deferred Inc. Taxes (410.2)	224,268-273		
46	(Less) Provision for Deferred Income Taxes—Cr. (411.2)	224,268-273		
47	Investment Tax Credit Adj.—Net (411.5)			
48	(Less) Investment Tax Credits (420)			
49	TOTAL Taxes on Other Inc. and Ded. *(Enter Total of 42 thru 48)*	–		
50	Net Other Income and Deductions *(Enter Total of lines 35, 40, 49)*	–	23,865	(7,978)
51	Interest Charges			
52	Interest on Long-Term Debt (427)	–	2,256,420	108,917
53	Amort. of Debt Disc. and Expense (428)			
54	Amortization of Loss on Reacquired Debt (428.1)			
55	(Less) Amort. of Premium on Debt-Credit (429)			
56	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)			
57	Interest on Debt to Assoc. Companies (430)	337		
58	Other Interest Expense (431)	337	77,652	25,778
59	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)	–	(2,215,856)	(108,917)
60	Net Interest Charges *(Enter Total of lines 52 thru 59)*	–	118,216	25,778
61	Income Before Extraordinary Items *(Enter Total of lines 21, 50 and 60)*	–	24,178	2,000
62	Extraordinary Items			
63	Extraordinary Income (434)			
64	(Less) Extraordinary Deductions (435)			
65	Net Extraordinary Items *(Enter Total of line 63 less line 64)*	–		
66	Income Taxes—Federal and Other (409.3)	258		
67	Extraordinary Items After Taxes *(Enter Total of line 65 less line 66)*	–		
68	Net Income *(Enter Total of lines 61 and 67)*			

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 for 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 for 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, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance – Beginning of Year		6,000
2	Changes *(Identify by prescribed retained earnings accounts)*		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439) *(Enter Total of lines 4 thru 8)*		
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439) *(Enter Total of lines 10 thru 14)*		
16	Balance Transferred from Income (Account 433 less Account 418.1)		24,178
17	(Less) Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436) *(Enter Total of lines 18 thru 21)*		
23	Dividends Declared – Preferred Stock (Account 437)		
24			
25			
26			
27			
28			
29	TOTAL Dividends Declared–Preferred Stock (Account 437) *(Enter Total of lines 24 thru 28)*		
30	Dividends Declared – Common Stock (Account 438)		
31			
32			
33			
34			
35			
36	TOTAL Dividends Declared–Common Stock (Account 438) *(Enter Total of lines 31 thru 35)*		
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		
38	Balance – End of Year *(Enter Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)*		30,178

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39	Patronage Capital	30,178
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	30,178
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)	
47	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)	30,178
48	TOTAL Retained Earnings (Account 215, 215.1, 216)	30,178
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)	
49	Balance – Beginning of Year (Debit or Credit)	
50	Equity in Earnings for Year (Credit) (Account 418.1)	
51	(Less) Dividends Received (Debit)	
52	Other Changes *(Explain)*	
53	Balance – End of Year	

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

STATEMENT OF CHANGES IN FINANCIAL POSITION

1. This statement is not restricted to those items which are noncurrent in nature. It is intended that this statement be flexible enough in nature so that latitude can be given, under the classification of "Other," to allow for disclosure of all significant changes and transactions, whether they are within or without the current asset and liability groups.

2. If the notes to the funds statement in the respondent's annual report to stockholders are applicable in every respect to this statement, such notes should be attached to page 122.

3. Under "Other" specify significant amounts and group others.

4. Codes Used:
   (a) Such as net increase-decrease in working capital, etc., other than changes in short term investments shown as item 4(e).
   (b) Bonds, debentures and other long-term debt.
   (c) Net proceeds or payments.
   (d) Include commercial paper.
   (e) Identify separately such items as investments, fixed assets, intangibles, etc.

5. Enter on page 122 clarifications and explanations.

Line No.	SOURCES OF FUNDS *(See instructions for explanation of codes)* (a)	Amounts (b)
1	Funds from Operations	
2	Net Income	24,178
3	Principal Non-Cash Charges (Credits) to Income	
4	Depreciation and Depletion	2,048
5	Amortization of *(Specify)*	
6	Provision for Deferred or Future Income Taxes (Net)	
7	Investment Tax Credit Adjustments	
8	(Less) Allowance for Other Funds Used During Construction	
9	Other (Net) Decrease in Working Capital	250,752
10		
11		
12		
13		
14		
15		
16		
17	TOTAL Funds from Operations *(Enter Total of lines 2 thru 16)*	276,978
18	Funds from Outside Sources (New Money)	
19	Long-Term Debt (b) (c)	29,855,055
20	Preferred Stock (c)	
21	Common Stock (c)	
22	Net Increase in Short-Term Debt (d)	898,344
23	Other (Net)	
24		
25		
26		
27		
28		
29		
30		
31	TOTAL Funds from Outside Sources *(Enter Total of lines 19 thru 30)*	30,753,399
32	Sale of Non-Current Assets (e)	
33		
34	Contributions from Associated and Subsidiary Companies	
35	Other (Net) (a)	
36		
37		
38		
39		
40		
41		
42		
43	TOTAL Sources of Funds *(Enter Total of lines 17, 31, 32 thru 42)*	31,030,377

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

STATEMENT OF CHANGES IN FINANCIAL POSITION (Continued)

Line No.	APPLICATION OF FUNDS (a)	Amounts (b)
44	Construction and Plant Expenditures (Including Land)	
45	Gross Additions to Utility Plant (Less Nuclear Fuel)	30,129,754
46	Gross Additions to Nuclear Fuel	1,041,320
47	Gross Additions to Common Utility Plant	
48	Gross Additions to Nonutility Plant	
49	(Less) Allowance for Other Funds Used During Construction	
50	Other	
51	TOTAL Applications to Construction and Plant Expenditures (Including Land) *(Enter Total of lines 45 thru 50)*	31,171,074
52	Dividends on Preferred Stock	
53	Dividends on Common Stock	
54	Funds for Retirement of Securities and Short-Term Debt	
55	Long-term Debt (b) (c)	
56	Preferred Stock (c)	
57	Redemption of Capital Stock	
58	Net Decrease in Short-term Debt (d)	
59	Other (Net)	
60		
61		
62		
63		
64		
65		
66	Purchase of Other Non-Current Assets (e)	
67	Prepayments and deferred charges	(97,470)
68	Preliminary Surveys	(43,227)
69	Investments in and Advances to Associated and Subsidiary Companies	
70	Other (Net) (a):	
71		
72		
73		
74		
75		
76		
77		
78	TOTAL Applications of Funds *(Enter Total of lines 51 thru 77)*	31,030,377

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 Changes in Financial Position, 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 Commission 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 Systems 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 attached hereto.

122(A)

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

1. Summary of significant accounting policies:

Basis of presentation - Vermont Electric Generation and Transmission Cooperative, Inc. (the Cooperative) is under the jurisdiction of the Federal Energy Regulating Commission, the Rural Electrification Administration and the Public Service Board of Vermont. It maintains its accounts in accordance with their prescribed Uniform System of Accounts.

Revenues and expenses - The Cooperative recognizes revenues for electric service and related purchased power costs in the months that bills are rendered as opposed to recognizing revenues and power costs in the month that service is received. This method of recognizing energy revenues and power costs is consistent with other rural electric cooperatives.

Depreciation - The Cooperative follows the policy of charging to operating expenses annual amounts of depreciation which allocate the cost of the utility plant over its estimated useful life. The Cooperative employs the straight-line method for determining the annual charge for depreciation. The estimated useful life used for transportation equipment was 5 years.

Maintenance and repairs are charged to expense as incurred.

Amortization - The Cooperative follows the policy of charging to operating expenses annual amounts of amortization which allocate the cost of various deferred charges over periods established by management for rate-making purposes. The Cooperative employs the straight-line method and periods of from 3 to 30 years for determining the annual charge for amortization. The total amount of amortization charged to expense accounts was \$140,505 and \$63,596 for 1984 and 1983, respectively.

Corporate structure and income taxes - The Company is a cooperative, nonprofit and non-stock membership corporation organized under provisions of the Electric Cooperative Act of Vermont. As a result, the Cooperative is exempt from federal income taxes in accordance with the Internal Revenue Code, Section 501(c)(12).

2. Other investments:

The investment account includes the following, at cost, as of December 31:

	1984	1983
Cooperative Finance Corporation membership	$ 1,000	$1,000
National Rural Electric Cooperative Association membership	10	10
N.R.U.C.F.C. Capital Term Certificates	17,167	-
N.R.U.C.F.C. Patronage Capital Certificates	18,278	-
	$36,455	$1,010

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

3. Deferred charges:

The balance in deferred charges consisted of the following as of December 31:

	Amortization Period	1984	1983
Seabrook investigation	None	$ 37,976	$ -
Millstone Unit No. 3 investigation	None	2,194	-
Preliminary survey - Hydroquebec tie-line - Phase 2	None	750	-
North Hartland alternate financing	None	1,836	-
Seabrook Unit 2	1985 - 2015	2,306,420	-
Preliminary survey - load control	None	49,125	34,097
Vermont Yankee downtime - 1983	1983 - 1986	103,989	166,389
Loan cost BF8	None	17,847	17,847
Preliminary survey - Hydroquebec tie-line - Phase 1	None	12,833	11,851
Vermont Yankee downtime	1981 - 1986	41,812	80,408
Loan costs BC8, BA4	None	27,559	3,117
Loan costs A8	None	50,118	28,961
Start-up costs	1981 - 1986	7,773	11,973
Pilgrim Unit No. 2	1984 - 2014	1,023,951	6,747
Preliminary survey - coal generation	None	-	47,153
Millstone Unit No. 3	None	-	6,505
Seabrook Units 1 & 2	None	-	6,878
		$3,684,183	$421,926

4. Long-term debt:

The Cooperative was indebted as follows as of December 31:

	1984	1983
Mortgage notes payable, U. S. Department of Agriculture Rural Electrification Administration (R.E.A.) - 5% mortgage notes	$14,537,074	$ 492,400
Mortgage notes payable Federal Financing Bank (F.F.B.) -		
11.082% mortgage note, advance dated 08/16/83	1,336,000	1,336,000
10.828% mortgage note, advance dated 12/29/83	1,500,000	1,500,000
10.497% mortgage note, advance dated 10/06/83	1,700,000	1,700,000
10.838% mortgage note, advance dated 08/19/83	2,023,000	-
10.478% mortgage note, advance dated 10/07/83	158,000	-
10.497% mortgage note, advance dated 10/06/83	1,800,000	-
11.033% mortgage note, advance dated 03/02/84	4,880,000	-

122(C)

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

4. Long-term debt (continued):

	1984	1983
12.926% mortgage note, advance dated 06/12/84	334,000	-
12.403% mortgage note, advance dated 09/10/84	2,000,000	-
11.908% mortgage note, advance dated 09/28/84	1,540,000	-
10.526% mortgage note, advance dated 12/04/84	1,500,000	-
10.497% mortgage note, advance dated 12/11/84	1,095,000	-
11.527% mortgage note, advance dated 12/06/84	480,380	-
	20,346,380	4,536,000
	$34,883,454	$5,028,400

The mortgage notes payable to R.E.A. are for 35-year terms each. During the first 5 years of each note, interest only is due quarterly. At the end of the first 5 years, principal amortization begins using a 30-year payback period. Payments of principal and interest are due quarterly in equal amounts. As of the end of 1984, principal amortization on $10,866,000 of the total outstanding had not commenced. The notes mature in various years through 2018. During 1984, $13,970,173 of R.E.A. debt was transferred to the Cooperative from Vermont Electric Cooperative, Inc.

The mortgage note advances from F.F.B. are for an initial 2-year term. At the end of the initial 2-year period, they can be rolled over for an additional term of from 2 to 5 years before being converted to long-term debt with principal amortization. The Cooperative may select a long-term maturity date which is the last day of a calendar year up to 34 years after the calendar year in which the advance was made. At the end of 1984, only one advance, $480,380, has been converted to a long-term maturity, due in 2016. The remaining advances could be extended to 1990 and 1991 before any amortization of principal would be required. Payments on these notes are due quarterly. During 1984, $3,981,000 of F.F.B. note advances were transferred to the Cooperative from Vermont Electric Cooperative, Inc.

At year end, a $2,500,000 note was approved with F.F.B. No amounts have been advanced.

All of the assets of the Cooperative are pledged as security under the above mentioned notes.

The following is a schedule of required principal payments on long-term debt from December 31, 1984:

1985	$ 90,942
1986	136,200
1987	200,773
1988	243,127
1989	259,050
Later years	33,953,362
	$34,883,454

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

5. Line of credit:

A line of credit agreement has been executed with the National Rural Utilities Cooperative Finance Corporation (C.F.C.) providing the Cooperative with short-term loans in the amount of $6,500,000 on a revolving basis for a period of twelve months which terminates on July 30, 1985. Interest on unpaid principal is payable quarterly. At December 31, 1984, $4,671,643 had been drawn of this line of credit.

6. Associated company:

Officers and some of the trustees of the Cooperative are also officers and trustees of the Vermont Electric Cooperative, Inc. (the VEC). Transactions between the Cooperative and VEC, and related amounts receivable and payable from these transactions, are summarized as follows:

	1984	1983
Purchases of energy by VEC	$2,968,381	$2,766,238
Accounting, construction and other services provided by VEC	$235,844	$152,309
Accounts receivable	$217,497	$214,869
Cash advance payable	$318,000	$ -

Summarized financial information for VEC is as follows:

	1984	1983
ASSETS		
Utility plant, net	$17,819,933	$36,028,839
Investments and other assets	1,422,779	1,296,524
Current assets	2,583,926	1,719,846
Deferred charges, net	531,126	603,657
	$22,357,764	$39,648,866
LIABILITIES AND EQUITIES		
Equities	$ 5,074,012	$ 4,127,219
Long-term debt	16,236,789	33,584,720
Current liabilities	1,029,735	1,914,397
Deferred credits	17,228	22,530
	$22,357,764	$39,648,866

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

6. Associated company (continued):

OPERATIONS	1984	1983
Operating revenues	$ 8,443,287	$ 7,318,318
Operating expenses	(7,969,952)	(7,535,417)
Nonoperating income	230,328	187,830
Net income (loss)	$ 703,663	$ (29,269)

In January, 1984, ownership of generation assets relating to Millstone Unit No. 3, Pilgrim Unit No. 2, Seabrook Units 1 & 2 (see Note 7), and related debt, were transferred from VEC to the Cooperative. The book value of these assets and related debt at the time of the transfer date amounted to approximately $19,424,000 and $17,948,000, respectively.

7. Nuclear power projects:

In January, 1984, all of the costs and related debt for Seabrook Units 1 & 2, Millstone Unit No. 3 and Pilgrim Unit No. 2 were transferred from an associated company to the Cooperative (see Note 6).

Pilgrim Unit No. 2 was cancelled in 1981. The Cooperative is amortizing its costs of $1,065,000 commencing in 1984 over a period of 30 years in line with the terms of the financing for the project. No significant additional costs are expected.

The Cooperative has entered into commitments to build Seabrook Unit 1 and Millstone Unit No. 3. The Cooperative's estimated costs to construct these projects is approximately $21,000,000 for the Seabrook Units, and approximately $13,260,000 for the Millstone Unit. Costs incurred through December 31, 1984 amounted to approximately $14,381,521 for the Seabrook Unit, and approximately $10,315,261 for the Millstone Unit. Completion of these nuclear generating units is contingent upon obtaining necessary regulatory approvals, permits and sufficient financing. During 1984, Seabrook Unit 2 was cancelled. Costs of $2,306,419, associated with Seabrook Unit 2, are reflected in the financial statements in deferred charges and will be amortized over 30 years starting in 1985.

The Seabrook Project represents a major commitment for the Cooperative. The Project has been subjected to delays and cost increases since construction begun in 1976 with the Public Service Company of New Hampshire ("PSNH") as lead owner.

Construction was temporarily suspended during April, 1984, when PSNH was having a severe financial crisis. Reduced level construction was resumed in July, 1984, after the joint owners modified the Joint Ownership Agreement to allow the transfer after regulatory approval of responsibility for the completion of Seabrook Unit 1 from PSNH to New Hampshire Yankee, an independent division of PSNH. Currently, New Hampshire Yankee estimates that Unit 1 will be completed for financial planning purposes in August, 1987.

122(F)

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

7. Nuclear power projects (continued):

The Vermont Public Service Board issued an order May 3, 1985 directing "Vermont utilities to attempt to disengage from the Seabrook Project by all prudent means including, specifically, offering their interests for sale and voting for cancellation". The PSB will hold further hearings in order to determine if it should order the utilities to stop further payments. Generic regulatory proceedings are underway in other states evaluating the reasonableness of completing Unit 1.

At present, possible financing plans considered by the joint owners include prefinancing Unit 1 completion costs through a new entity known as "Newbrook", obtaining a satisfactory bank letter of credit or being an "A" rated utility.

The Cooperative is unable to determine if all approvals and financings can be arranged in order to allow timely completion of Unit 1.

8. Purchased power:

Power purchased by the Cooperative is obtained under a life-of-the-unit purchase contract from the Vermont Nuclear Station ("Vermont Yankee"), operated by the Vermont Yankee Nuclear Power Corporation and from the Merrimack Unit No. 2 ("Merrimack"), owned and operated by the Public Service Company of New Hampshire. The Merrimack contract expires in 1998. The Vermont Yankee and Merrimack purchase contracts are take or pay contracts which require the Cooperative to pay its proportionate share of the fixed costs of such facilities even during periods when power is not being generated by such facilities or being delivered under such contracts. Such fixed costs represent a substantial portion of the total cost for power paid by the Cooperative from these sources. Vermont Yankee is scheduled to be shut down eight months for pipe repairs beginning in September, 1985.

The Cooperative, along with other utilities having entitlement contracts with Vermont Yankee, has entered into an agreement with Vermont Yankee under which the Cooperative is responsible for its proportionate share of plant decommissioning expenses. Annual contributions are made to a decommissioning fund until Vermont Yankee's operating license expires in 2007. As of December 31, 1984 and 1983, the Cooperative's share of decommissioning expense was $40,790 and $16,255, respectively.

The Cooperative entered into an agreement with three operating companies of the Northeast Utilities System, Connecticut Light and Power Company ("CL&P"), the Hartford Electric Light Company ("HELCO") and Western Massachusetts Electric Company ("WMECO"), to purchase a portion of the capacity and output of five gas turbine generating units owned by CL&P, HELCO and WMECO. The agreement runs from November, 1982 through October, 1985. These agreements require the Cooperative to pay its proportionate share of fixed costs regardless of the actual output of any of the units at any time. Such fixed costs represent a substantial portion of the total cost for power paid by the Cooperative.

122(G)

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

8. Purchased power (continued):

The Cooperative contracted to purchase approximately 4016 KW's of Hydro-Quebec power through an agreement with the State of Vermont. In addition, under an agreement with VELCO, the Cooperative has a 2.68% ownership in the Highgate converter station presently being built to transmit the Hydro-Quebec power. As of December 31, 1984, the Cooperative has invested approximately $245,000 out of a total obligation of approximately $737,000.

The Cooperative is a member of the New England Power Pool ("NEPOOL"). Electric power supply facilities in New England are operated under Cooperative arrangements provided for by the NEPOOL Agreement which became effective in 1971. This agreement provides for joint planning and operation of generation and transmission facilities, and also incorporates generating capacity reserve obligations and provisions regarding the use of major transmission lines and payment for such use.

The Cooperative has a contract with Central Vermont Public Service Corporation ("CVPSC") to purchase power from CVPSC. From November, 1983 through October, 1984, 17,200 KW's were purchased, and from November, 1984 through October, 1985, 16,000 KW's are purchased. The contract expires in 1992.

In 1984, the Cooperative entered into an agreement through VELCO to participate in the savings associated with the High Voltage Direct Current transmission line Phase I and Phase II being constructed in Vermont for the transmission of Hydro-Quebec power to NEPOOL.

The percentage of energy acquired from the above power contracts for the years ended December 31 is as follows:

	1984	1983
Central Vermont Public Service Corporation	72.8%	74.3%
Vermont Yankee	19.1	18.6
Merrimack 2	7.0	6.1
NEPOOL	.9	.9
Northeast Utilities	.2	.1
	100.0%	100.0%

9. Commitments:

The Cooperative is in the process of building a hydroelectric project in North Hartland, Vermont. The Cooperative estimates that total development costs for the project will amount to approximately $14,000,000. At present, negotiations are underway for the sale and leaseback of this facility. It is anticipated that, if the sale is consummated, the proceeds will be used to reduce the outstanding debt with R.E.A. and F.F.B.

VERMONT ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 1984 AND 1983

10. Contingency:

The Cooperative is in the process of negotiating a settlement with a former contractor relating to construction costs of the North Hartland Hydro Project. The Cooperative has made an offer to settle the claim, subject to R.E.A. approval, for an amount of approximately $500,000. The Cooperative currently has provided approximately $150,000 on the books of the Cooperative. No additional liabilities have been provided in these financial statements at the present time.

11. Subsequent events:

In March, 1985, the Vermont Department of Public Service filed a lawsuit against the Vice President and Executive Manager of Vermont Electric Generation and Transmission Cooperative, Inc., its board members and the Cooperative. The suit seeks to void the granting of the $100,000 bonus, compensatory damages of $100,000 from each defendant, plus interest, and punitive damages against each defendant of $100,000, all for the benefit of Vermont Electric Generation and Transmission Cooperative, Inc., its members, Vermont Electric Cooperative, Inc. and Vermont Electric Cooperative, Inc. rate payers.

In March, 1985, the Vermont Electric Cooperative, Inc. filed a lawsuit against the trustees and the Vice President and Executive Manager of the Cooperative alleging breach of fiduciary duties and waste of corporate assets and seeking to recover a $100,000 cash bonus, a 1980 vehicle, compensatory damages of $150,000, plus interest, and punitive damages of $100,000 against each defendant. At the present time, the suit is still in the discovery stages.

In March, 1985, an additional $550,000 was advanced to the Cooperative by Vermont Electric Cooperative, Inc.

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19___

NOTES TO FINANCIAL STATEMENTS (Continued)

FERC FORM NO. 1 (REVISED 12-84)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	32,640	32,640				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL *(Enter Total of lines 3 thru 7)*	32,640	32,640				
9	Leased to Others						
10	Held for Future Use						
11	Construction Work in Progress	39,059,369	39,059,369				
12	Acquisition Adjustments						
13	TOTAL Utility Plant *(Enter Total of lines 8 thru 12)*	39,092,009	39,092,009				
14	Accum. Prov. for Depr., Amort., & Depl.	4,948	4,948				
15	Net Utility Plant *(Enter Total of line 13 less 14)*	39,087,061	39,087,061				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	4,948	4,948				
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant						
22	TOTAL In Service *(Enter Total of lines 18 thru 21)*	4,948	4,948				
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others *(Enter Total of lines 24 and 25)*						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use *(Enter Total of lines 28 and 29)*						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) *(Enter Total of lines 22, 26, 30, 31, and 32)*	4,948	4,948				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

NUCLEAR FUEL MATERIALS (Accounts 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)	Changes During Year: Amortization (d)	Changes During Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in Process of Refinement, Conversion, Enrichment & Fabrication (120.1)	117,163	864,425			981,588
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction	4,336	176,895			181,231
5	Other Overhead Construction Costs					
6	SUBTOTAL *(Enter Total of lines 2 thru 5)*	121,499				1,162,819
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL *(Enter Total of lines 8 and 9)*					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	Less Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	121,499				1,162,819
14	TOTAL Nuclear Fuel Stock *(Enter Total of lines 6, 11, and 12 less line 13)*					
15	Estimated Net Salvage Value of Nuclear Materials in line 9					
16	Estimated Net Salvage Value of Nuclear Materials in line 11					
17	Estimated 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 *(Enter Total of lines 19, 20, and 21)*					

FERC FORM NO. 1 (REVISED 12-83)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

ELECTRIC PLANT IN SERVICE (Accounts 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 amounts.

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

(Continued on page 204)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	19,167					19,167
3	(302) Franchises and Consents						
4	(303) Miscellaneous Intangible Plant	500					500
5	TOTAL Intangible Plant *(Enter Total of lines 2, 3, and 4)*	19,667					19,667
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						
18	(321) Structures and Improvements						
19	(322) Reactor Plant Equipment						
20	(323) Turbogenerator Units						
21	(324) Accessory Electric Equipment						
22	(325) Misc. Power Plant Equipment						
23	TOTAL Nuclear Production Plant *(Enter Total of lines 17 thru 22)*						
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)*						

FERC FORM NO. 1 (REVISED 12-81) Page 203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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						
40	(346) Misc. Power Plant Equipment						
41	TOTAL Other Production Plant *(Enter Total of lines 34 thru 40)*						
42	TOTAL Production Plant *(Enter Total of lines 15, 23, 32, and 41)*						
43	3. TRANSMISSION PLANT						
44	(350) Land and Land Rights						
45	(352) Structures and Improvements						
46	(353) Station Equipment						
47	(354) Towers and Fixtures						
48	(355) Poles and Fixtures						
49	(356) Overhead Conductors and Devices						
50	(357) Underground Conduit						
51	(358) Underground Conductors and Devices						
52	(359) Roads and Trails						
53	TOTAL Transmission Plant *(Enter Total of of lines 44 thru 52)*						
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						

INTENTIONALLY BLANK

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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

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. Attach supplemental statement showing 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 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. In showing the clearance of 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 requirements 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 purchaser, 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
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						
73	(391) Office Furniture and Equipment						
74	(392) Transportation Equipment	12,973					12,973
75	(393) Stores Equipment						
76	(394) Tools, Shop and Garage Equipment						
77	(395) Laboratory Equipment						
78	(396) Power Operated Equipment						
79	(397) Communication Equipment						
80	(398) Miscellaneous Equipment						
81	SUBTOTAL *(Enter Total of lines 71 thru 80)*	12,973					12,973
82	(399) Other Tangible Property						
83	TOTAL General Plant *(Enter Total of lines 81 and 82)*	12,973					12,973
84	TOTAL (Accounts 101 and 106)	32,640					32,640
85	(102) Electric Plant Purchased (See Instr. 8)						
86	Less (102) Electric Plant Sold *(See Instr. 8)*						
87	(103) Experimental Electric Plant Unclassified						
88	TOTAL Electric Plant in Service	32,640					32,640

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

1. Report below the information called for concerning electric plant leased to others.

2. In column (c) give the date of Commission authorization of the lease of electric plant to others.

Line No.	Name of Lessee (Designate associated companies with an asterisk) (a)	Descripton of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Land and Land Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Other Property:			
21				
22				
23				
24	INTENTIONALLY BLANK			
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46				
47	TOTAL			

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(Next Page is 210)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

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 Demonstration (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	North Hartland Tie Line	497,487
2		
3	North Hartland Generating Facility	12,476,070
4		
5	Millstone 3 Transmission	13,331
6		
7	Millstone 3 Generating Facility	9,906,830
8		
9	Seabrook Project Transmission	44,343
10		
11	Seabrook Project Generating Facility	15,875,879
12		
13	Highgate Tie Line	245,429
14		
15		
16		
17		
18		
19		
20		
21		
22		
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46	TOTAL	39,059,369

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

CONSTRUCTION OVERHEADS—ELECTRIC

1. List in column (a) the 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 212 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 212 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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11	SEE PAGE 212	
12		
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46	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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.

Due to the nature and number of the Cooperative's work orders, all overhead type charges are assessed directly to their work in progress accounts.

Labor charges are based on time sheet data.

Project	Labor	Other	Total
North Hartland	39,021	38,229	77,250
Millstone 3	1,679	988	2,667
Seabrook	15,465	9,661	25,126
Highgate	234	143	317
	56,399	49,021	105,420

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 actually 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	S		
(2)	Short Term Interest			s
(3)	Long Term Debt	D		d
(4)	Preferred Stock	P		p
(5)	Common Equity	C		c
(6)	Total Capitalization		100%	
(7)	Average Construction Work in Progress Balance	W		

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

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

4. Weighted Average Rate Actually Used for the Year:
   a. Rate for Borrowed Funds– 8.537%
   b. Rate for Other Funds–

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

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 202-204, column (d), 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	2,900	2,900		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Expenses of Electric Plant Leased to Others				
5	Transportation Expenses—Clearing	2,048	2,048		
6	Other Clearing Accounts				
7	Other Accounts *(Specify)*				
8					
9	TOTAL Depreciation Provisions for Year *(Enter Total of lines 3 thru 8)*	2,048	2,048		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Charges for Plant Retired *(Enter Total of lines 11 thru 13)*				
15	Other Debit or Credit Items *(Describe)*				
16					
17	Balance End of Year *(Enter Total of lines 1, 9, 14, 15, and 16)*	4,948	4,948		

Section B. Balances at End of Year According to Functional Classifications

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)
18	Steam Production				
19	Nuclear Production				
20	Hydraulic Production—Conventional				
21	Hydraulic Production—Pumped Storage				
22	Other Production				
23	Transmission				
24	Distribution				
25	General	4,948	4,948		
26	TOTAL *(Enter Total of lines 18 thru 25)*	4,948	4,948		

Next Page is 215

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an 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 43), or (2) other nonutility property (line 44).

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
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43	Minor Item Previously Devoted to Public Service			
44	Minor Items – Other Nonutility Property			
45	TOTAL			

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, *Investment in Subsidiary Companies.*

2. Provide a subheading for each company and list thereunder 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.

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 from investments, including such revenues from 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 different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on line 23, column (a) the total cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
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12				INTENTIONALLY	BLANK			
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21								
22								
23	Total Cost of Account 123.1: $______		TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected—debited or credited. Show separately debits 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)			
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)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to – Other			
11	TOTAL Account 154 *(Enter Total of lines 5 thru 10)*			
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss (*Include in the description the date of loss, the date of Commission authorization to use (Account 182.1 and period of amortization (mo, yr to mo, yr).)*) (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR: Account Charged (d)	WRITTEN OFF DURING YEAR: Amount (e)	Balance End of Year (f)
1	Pilgrim 2 - Abandoned Generation					
2	Project	1,059,037	35,666	407.1	35,666	1,023,371
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19						
20	TOTAL	1,059,037	35,666		35,666	1,023,371

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (ACCOUNT 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 Account 182.2, and period of amortization (mo, yr to mo, yr.)*) (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR: Account Charged (d)	WRITTEN OFF DURING YEAR: Amount (e)	Balance at End of Year (f)
21						
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50						
51	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

MISCELLANEOUS DEFERRED 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 items (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 Deferred Debit (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Misc. Def. Dr.-Start Up	11,973		930.2	4,200	7,773
2	Transfer Ownership-Pilgrim 2	6,747	5,042	182.1	11,789	-0-
3	Transfer Ownership-Millstone 3	6,505	4,005	107.603	10,510	-0-
4	Transfer Ownership-Seabrook	6,877	5,738	107.604	12,615	-0-
5	VT-Yankee Downtime-Dec.1980	80,408	--	558	38,596	41,812
6	Assume BC8-BA4 Loans	3,117	2,616	930.2	5,733	-0-
7	Acquire A-8 Loan	28,961	21,157			50,118
8	VT-Yankee Spring'83 Capacity	166,389		558	62,400	103,989
9	Dkt.4936-Investigate M3	-0-				2,194
10	N. Hartland Alternative Fin.	-0-				1,836
11						
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47	Misc. Work in Progress					
48	DEFERRED REGULATORY COMMISSION EXPENSES *(See pages 350-351)*					
49	TOTAL	310,977				207,722

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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.
3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5			
6			
7	Other		
8	TOTAL Electric *(Enter Total of lines 2 thru 7)*		
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas *(Enter Total of lines 10 thru 15)*		
17	Other *(Specify)*		
18	TOTAL (Account 190) *(Enter Total of lines 8, 16 and 17)*		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

CAPITAL STOCK (Accounts 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 the 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.

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 noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

6. 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 purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)	OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent.) Shares (e)	Amount (f)	HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217) Shares (g)	Cost (h)	IN SINKING AND OTHER FUNDS Shares (i)	Amount (j)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, 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 an 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)
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46	TOTAL		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) *Donations Received from Stockholders* (Account 208)—State amount and give brief explanation of the origin and purpose of each donation.

(b) *Reduction in Par or Stated Value of Capital Stock* (Account 209)—State amount and give brief explanation of the capital changes which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) *Gain on Resale or Cancellation of Reacquired Capital Stock* (Account 210)—Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) *Miscellaneous Paid-In Capital* (Account 211)—Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Washington Electric Cooperative, Inc. Membership Fee	5.00
2	HELCO Membership Fee	5.00
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40	TOTAL	10.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1984

DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of 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)
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11		
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19		
20		
21	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of year of capital stock expenses 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 of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
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8	INTENTIONALLY BLANK	
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

LONG TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet the account particulars (details) concerning long-term debt included in Accounts 221, *Bonds*, 222, *Reacquired Bonds*, 223, *Advances from Associated Companies*, and 224, *Other Long-Term Debt*.

2. In column (a), for new issues, give Commission authorization numbers and dates.

3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.

4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.

5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

6. In column (b) show the principal amount of bonds or other long-term debt originally issued.

7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.

9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

10. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.

11. Explain any debits and credits other than amortization debited to Account 428, *Amortization of Debt Discount and Expense*, or credited to Account 429, *Amortization of Premium on Debt — Credit*.

12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote including name of the pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, *Interest on Long-Term Debt* and Account 430, *Interest on Debt to Associated Companies*.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate *(For new issue, give Commission Authorization numbers and dates)* *(a)*	Principal Amount of Debt Issued *(b)*	Total Expense, Premium or Discount *(c)*	Nominal Date of Issue *(d)*	Date of Maturity *(e)*	AMORTIZATION PERIOD Date From *(f)*	Date To *(g)*	Outstanding (Total amount outstanding without reduction for amounts held by respondent) *(h)*	Interest for Year Amount *(i)*
1	REA - BE4 Loan	500,000						485,671	24,493
2									
3	REA - BA4 Loan	15,816,000						14,051,403	702,453
4									
5	FFB - TAI	13,406,000						9,131,000	582,728
6									
7	FFB - BC8/A-8	11,920,380						11,215,380	946,747
8									
9									
10									
11									
12									
13									
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15									
16									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 19 84

LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17									
18									
19									
20									
21									
22									
23									
24									
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26									
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47									
48									
49	TOTAL	41,642,380						34,883,454	2,256,421

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 known, 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.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (b)	Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)	BALANCE AT END OF YEAR: Taxes Accrued (Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)
1	Gross Revenue - State of Vermont	--	--	9	9	--	--	--
2								
3								
4								
5								
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7								
8								
9								
10								
11								
12								
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14								
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27								
28	TOTAL	--	--	9	9	--	--	--

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. *If any tax (exclude Federal and state income taxes) covers more than 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 footnote. 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. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (1). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	DISTRIBUTION OF TAXES CHARGED *(Show utility department where applicable and account charged.)*			
	Electric (Account 408.1, 409.1) *(i)*	Extraordinary Items (Account 409.3) *(j)*	Adjustment to Ret. Earnings (Account 439) *(k)*	Other *(l)*
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28	TOTAL			

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, 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.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29		
30	INTENTIONALLY BLANK	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 Beginning 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)	Balance at End of Year (h)	Average Period of Allocation to Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8	TOTAL								
9	Other *(List separately and show 3%, 4%, 7%, 10% and TOTAL)*								
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

OTHER DEFERRED 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 of Other Deferred Credit (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1						
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47	TOTAL					

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 relating to amortizable property.

2. For Other *(Specify)*, include deferrals relating to other

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

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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

income and deductions.

3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) *(e)*	Amounts Credited (Account 411.2) *(f)*	Acct. No. *(g)*	Amount *(h)*	Acct. No. *(i)*	Amount *(j)*	Balance at End of Year *(k)*	Line No.
							1
							2
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							21

NOTES (Continued)

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

ACCUMULATED DEFERRED INCOME TAXES–OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. For Other *(Specify)*, include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR: Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric			
3	Gas			
4	Other *(Define)*			
5	TOTAL *(Enter Total of lines 2 thru 4)*			
6	Other *(Specify)*			
7				
8				
9	TOTAL Account 282 *(Enter Total of lines 5 thru 8)*			
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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

income and deductions.

3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Acct. No.	Amount	Acct. No.	Amount		
(e)	*(f)*	*(g)*	*(h)*	*(i)*	*(j)*	*(k)*	
							1
							2
							3
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NOTES (Continued)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

ACCUMULATED DEFERRED 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

Line No.	Account Subdivisions *(a)*	Balance at Beginning of Year *(b)*	CHANGES DURING YEAR Amounts Debited (Account 410.1) *(c)*	CHANGES DURING YEAR Amounts Credited (Account 411.1) *(d)*
1	Account 283			
2	Electric			
3				
4				
5				
6				
7				
8	Other			
9	TOTAL Electric *(Enter Total of lines 2 thru 8)*			
10	Gas			
11				
12				
13				
14				
15				
16	Other			
17	TOTAL Gas *(Enter Total of lines 10 thru 16)*			
18	Other *(Specify)*			
19	TOTAL Account 283 *(Enter Total of lines 9, 17 and 18)*			
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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

income and deductions.

Provide in the space below explanations for pages 272 and 273. Include amounts relating to insignificant items under Other

4. Use separate pages as required

Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	ADJUSTMENTS Debits		Credits		Balance at End of Year	Line No.
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
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NOTES (Continued)

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

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 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 previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

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 page 108, Important Changes During Year, for important new territory added and important rate increases 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.

Line No.	Title of Account (a)	OPERATING REVENUES: Amount for Year (b)	OPERATING REVENUES: Amount for Previous Year (c)	MEGAWATT HOURS SOLD: Amount for Year (d)	MEGAWATT HOURS SOLD: Amount for Previous Year (e)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Year (f)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales						
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial) *(See Instr. 4)*						
5	Large (or Industrial) *(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	6,700,594	5,655,323	183,165	161,332	3	2
12	TOTAL Sales of Electricity	6,700,594 *	5,655,323	183,165 **	161,332	3	2
13	(Less)(449.1) Provision for Rate Refunds	--	--				
14	TOTAL Reve. Net of Prov. for Refunds	6,700,594	5,655,323				
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						
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	625	2,275				
22							
23							
24							
25							
26	TOTAL Other Operating Revenues	625	2,275				
27	TOTAL Electric Operating Revenues	6,701,219	5,657,598				

*Includes $ ________ unbilled revenues.

**Includes ________ MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1						
2						
3						
4						
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39						
40						
41	Total Billed					
42	Total Unbilled Rev. *(See Instr. 6)*					
43	TOTAL					

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	Northeast Utilities								
2	Service Co.	DP	X		VELCO System				
3	North Attleboro								
4	Electric Department	DP	X		VELCO System				
5	Vermont Electric								
6	Cooperative, Inc.	FP(P)			CVPSC & GMP Subtransm. System				
7									
8									
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
							1
		73,269		2,813,447		2,813,447	2
							3
		21,985		860,295		860,295	4
							5
		87,911	1,732,764	1,294,088		3,026,852	6
							7
							8
							9
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred—Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	TOTAL Operation *(Enter Total of lines 4 thru 11)*		
13	Maintenance		
14	(510) Maintenance Supervision and Engineering		
15	(511) Maintenance of Structures		
16	(512) Maintenance of Boiler Plant		
17	(513) Maintenance of Electric Plant		
18	(514) Maintenance of Miscellaneous Steam Plant		
19	TOTAL Maintenance *(Enter Total of lines 14 thru 18)*		
20	TOTAL Power Production Expenses—Steam Power *(Enter Total of lines 12 and 19)*		
21	B. Nuclear Power Generation		
22	Operation		
23	(517) Operation Supervision and Engineering		
24	(518) Fuel		
25	(519) Coolants and Water		
26	(520) Steam Expenses		
27	(521) Steam from Other Sources		
28	(Less) (522) Steam Transferred—Cr.		
29	(523) Electric Expenses		
30	(524) Miscellaneous Nuclear Power Expenses		
31	(525) Rents		
32	TOTAL Operation *(Enter Total of lines 23 thru 31)*		
33	Maintenance		
34	(528) Maintenance Supervision and Engineering		
35	(529) Maintenance of Structures		
36	(530) Maintenance of Reactor Plant Equipment		
37	(531) Maintenance of Electric Plant		
38	(532) Maintenance of Miscellaneous Nuclear Plant		
39	TOTAL Maintenance *(Enter Total of lines 34 thru 38)*		
40	TOTAL Power Production Expenses—Nuclear Power *(Enter Total of lines 32 and 39)*		
41	C. Hydraulic Power Generation		
42	Operation		
43	(535) Operation Supervision and Engineering		
44	(536) Water for Power		
45	(537) Hydraulic Expenses		
46	(538) Electric Expenses		
47	(539) Miscellaneous Hydraulic Power Generation Expenses		
48	(540) Rents		
49	TOTAL Operation *(Enter Total of lines 43 thru 48)*		

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering		
53	(542) Maintenance of Structures		
54	(543) Maintenance of Reservoirs, Dams, and Waterways		
55	(544) Maintenance of Electric Plant		
56	(545) Maintenance of Miscellaneous Hydraulic Plant		
57	TOTAL Maintenance *(Enter Total of lines 52 thru 56)*		
58	TOTAL Power Production Expenses—Hydraulic Power *(Enter Total of lines 49 and 57)*		
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering		
62	(547) Fuel		
63	(548) Generation Expenses		
64	(549) Miscellaneous Other Power Generation Expenses		
65	(550) Rents		
66	TOTAL Operation *(Enter Total of lines 61 thru 65)*		
67	Maintenance		
68	(551) Maintenance Supervision and Engineering		
69	(552) Maintenance of Structures		
70	(553) Maintenance of Generating and Electric Plant		
71	(554) Maintenance of Miscellaneous Other Power Generation Plant		
72	TOTAL Maintenance *(Enter Total of lines 68 thru 71)*		
73	TOTAL Power Production Expenses—Other Power *(Enter Total of lines 66 and 72)*		
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	6,056,376	5,129,063
76	(556) System Control and Load Dispatching	26,841	24,345
77	(557) Other Expenses	93,257	37,032
78	TOTAL Other Power Supply Expenses *(Enter Total of lines 75 thru 77)*	6,176,474	5,190,440
79	TOTAL Power Production Expenses *(Enter Total of lines 20, 40, 58, 73, and 78)*	6,176,474	5,190,440
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering		
83	(561) Load Dispatching		
84	(562) Station Expenses		
85	(563) Overhead Line Expenses		
86	(564) Underground Line Expenses		
87	(565) Transmission of Electricity by Others	252,804	324,300
88	(566) Miscellaneous Transmission Expenses		33,017
89	(567) Rents		
90	TOTAL Operation *(Enter Total of lines 82 thru 89)*	252,804	357,317
91	Maintenance		
92	(568) Maintenance Supervision and Engineering		
93	(569) Maintenance of Structures		
94	(570) Maintenance of Station Equipment		
95	(571) Maintenance of Overhead Lines		
96	(572) Maintenance of Underground Lines		
97	(573) Maintenance of Miscellaneous Transmission Plant		
98	TOTAL Maintenance *(Enter Total of lines 92 thru 97)*		
99	TOTAL Transmission Expenses *(Enter Total of lines 90 and 98)*	252,804	357,317
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering		
103	(581) Load Dispatching		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(582) Station Expenses		
106	(583) Overhead Line Expenses		
107	(584) Underground Line Expenses		
108	(585) Street Lighting and Signal System Expenses		
109	(586) Meter Expenses		
110	(587) Customer Installations Expenses		
111	(588) Miscellaneous Distribution Expenses		
112	(589) Rents		
113	TOTAL Operation *(Enter Total of lines 102 thru 112)*		
114	Maintenance		
115	(590) Maintenance Supervision and Engineering		
116	(591) Maintenance of Structures		
117	(592) Maintenance of Station Equipment		
118	(593) Maintenance of Overhead Lines		
119	(594) Maintenance of Underground Lines		
120	(595) Maintenance of Line Transformers		
121	(596) Maintenance of Street Lighting and Signal Systems		
122	(597) Maintenance of Meters		
123	(598) Maintenance of Miscellaneous Distribution Plant		
124	TOTAL Maintenance *(Enter Total of lines 115 thru 123)*		
125	TOTAL Distribution Expenses *(Enter Total of lines 113 and 124)*		
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision		
129	(902) Meter Reading Expenses		
130	(903) Customer Records and Collection Expenses	1,069	997
131	(904) Uncollectible Accounts		
132	(905) Miscellaneous Customer Accounts Expenses	1,069	[illegible]97
133	TOTAL Customer Accounts Expenses *(Enter Total of lines 128 thru 132)*		
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision		
137	(908) Customer Assistance Expenses		
138	(909) Informational and Instructional Expenses		
139	(910) Miscellaneous Customer Service and Informational Expenses		
140	TOTAL Cust. Service and Informational Exp. *(Enter Total of lines 136 thru 139)*		
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision		
144	(912) Demonstrating and Selling Expenses		
145	(913) Advertising Expenses		
146	(916) Miscellaneous Sales Expenses		
147	TOTAL Sales Expenses *(Enter Total of lines 143 thru 146)*		
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	23,251	21,043
151	(921) Office Supplies and Expense	7,438	7,621
152	(Less) (922) Administrative Expenses Transferred—Cr.		
153	(923) Outside Services Employe	9,426	18,139
154	(924) Property Insurance		
155	(925) Injuries and Damages	997	868
156	(926) Employee Pensions and Benefits		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
157	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
158	(927) Franchise Requirements		
159	(928) Regulatory Commission Expenses	37,976	806
160	(929) Duplicate Charges–Cr.		
161	(930.1) General Advertising Expenses		
162	(930.2) Miscellaneous General Expenses	37,581	24,597
163	(931) Rents		
164	TOTAL Operation *(Enter Total of lines 150 thru 163)*	116,669	73,074
165	Maintenance		
166	(935) Maintenance of General Plant		
167	TOTAL Administrative and General Expenses *(Enter Total of lines 164 thru 166)*	116,669	73,074
168	TOTAL Electric Operation and Maintenance Expenses *(Enter Total of lines 79, 99, 125, 133, 140, 147, and 167)*	6,547,016	5,621,828

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 employees 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)	December 16, 1984
2. Total Regular Full-Time Employees	3*
3. Total Part-Time and Temporary Employees	
4. Total Employees	3

*Three employees are also employed by Vermont Electric Cooperative, Inc. (VT 7)

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

PURCHASED POWER (Account 555)
(Except interchange power)

1. Report power purchased for resale during the year. Report on page 328 particulars (details) concerning interchange power transactions during the year; do not include such figures on this page.

2. Provide in column (a) subheadings and classify purchases as to: (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b) using the following codes: FP, firm power; DP, dump or surplus power; O, other. Describe the nature of any purchases classified as Other Power. Enter an "x" in column (c) if purchase involves import across a state line.

3. Report separately firm, dump, and other power purchased

Line No.	Purchased From (a)	Statistical Classification (b)	Import Across State Lines (c)	FERC Rate Schedule No. of Seller (d)	Point of Receipt (e)	Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	VELCO								
2	(1) Merrimack 2	FP	X		VELCO Trans. System		1,909	1,909	1,909
3									
4	(2) Vermont Yankee	FP			" " "		5,561	5,561	5,561
5	Nepool Economy	DP	X		" " "				
6									
7	(3) Northeast Util.	FP	X		" " "		10,100	11,518	13,612
8									
9	(4) CVPSC	FP			CVPSC - Sub.		17,200	17,100	17,200
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11									
12									
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

PURCHASED POWER (Account 555) (Continued)
(Except interchange power)

from the same company.

4. If receipt of power is at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; SS, seller owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billing, enter this number in column (g). Base the number of megawatts of maximum demand shown in columns (h) and (i) on actual monthly readings. Furnish those figures whether they are used or not in the determination of demand charges. Show in column (j) type of demand reading (i.e. instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours purchased as shown by the power bills rendered to the purchases.

7. Explain in a footnote any amount entered in column (o), such as fuel or other adjustments.

Type of Demand Reading (j)	Voltage at Which Received (k)	Megawatt Hours (l)	Cost Of Energy: Demand Charges (m)	Cost Of Energy: Energy Charges (n)	Cost Of Energy: Other Charges (o)	Cost Of Energy: Total (m+n+o) (p)	Line No.
							1
1 Hr.	115 KV	12,815	95,412	193,869		289,281	2
							3
1 Hr.	115 KV	35,002	1,013,435	231,125	100,996	1,345,556	4
1 Hr.	115 KV	1,603	(7,414)	153,919		146,505	5
							6
1 Hr.	115 KV	501	126,020	52,002		178,022	7
							8
1 Hr.	34.5/12.5						9
	/7.2	33,244	2,181,202	1,848,466		4,029,668	10
							11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

SUMMARY OF INTERCHANGE ACCORDING TO COMPANIES AND POINTS OF INTERCHANGE
(Included in Account 555)

1. Report below all of the megawatt-hours received and delivered during the year. For receipts and deliveries under interchange power agreements, show the net charge or credit resulting therefrom.

2. Provide subheadings and classify interchanges as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each interchange across a state line place an "x" in column (b).

3. Furnish particulars (details) of settlements for interchange power in a footnote or on a supplemental page; include the name of each company, the nature of the transaction, and the dollar amounts involved. If settlement for any transaction also includes credit or debit amounts other than for increment generation expenses, show such other component amounts separately, in addition to debit or credit for increment generation expenses, and give a brief explanation of the factors and principles under which such other component amounts were determined. If such settlement represents the net of debits and credits under an interconnection, power pooling, coordination, or other such arrangement, submit a copy of the annual summary of transactions and billings among the parties to the agreement. If the amount of settlement reported in this schedule for any transaction does not represent all of the charges and credits covered by the agreement, furnish in a footnote a description of the other debits and credits and state the amounts and accounts in which such other amounts are included for the year.

Line No.	Name of Company (a)	Interchanges Across State Lines (b)	FERC Rate Schedule Number (c)	Point of Interchange (d)	Voltage at Which Interchanged (e)	Megawatt Hours Received (f)	Megawatt Hours Delivered (g)	Megawatt Hours Net Difference (h)	Amount of Settlement (i)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

TRANSMISSION OF ELECTRICITY FOR OR BY OTHERS (Accounts 456 and 565)

(Including transactions sometimes referred to as "wheeling")

1. Describe below and give particulars of any transactions by respondent during the year for transmission of electricity for or by others during year, including transactions sometimes referred to as wheeling.

2. Provide separate subheadings for: (a) *Transmission of Electricity for Others* (included in Account 456) and (b) *Transmission of Electricity by Others* (Account 565).

3. Furnish the following information in the space below concerning each transaction:

   (a) Name of company and description of service rendered or received. Designate associated companies.

   (b) Points of origin and termination of service specifying also any transformation service involved.

   (c) MWh received and MWh delivered.

   (d) Monetary settlement received or paid and basis of settlement, included in Account 456 or 565.

   (e) Nonmonetary settlement, if any, specifying the MWh representing compensation for the service, specifying whether such power was firm power, dump or other power, and state basis of settlement. If nonmonetary settlement was other than MWh describe the nature of such settlement and basis of determination.

   (f) Other explanations which may be necessary to indicate the nature of the reported transactions. Include in such explanations a statement of any material services remaining to be received or furnished at end of year and the accounting recorded to avoid a possible material distortion of reported operating income for the year.

A/C 565

VELCO	208,224
Northeast Utilities	67,344
N.E.P.C.O.	44,580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)		Amount (b)
1	Industry Association Dues		1,050
2	Nuclear Power Research Expenses		
3	Other Experimental and General Research Expenses		
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent		
5	Other Expenses *(List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less than $5,000 by classes if the number of items so grouped is shown)*		
6	Assuming BA4, BC8 Debt	930.2	5,733
7			
8	Amortization of start-up expense	930.2	4,200
9			
10	Association Meetings	930.4	13,670
11			
12	Directors	930.5	12,928
13			
14			
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46	TOTAL		37,581

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition 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 B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute the 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 subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column (b) 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 (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant				
2	Steam Production Plant				
3	Nuclear Production Plant				
4	Hydraulic Production Plant—Conventional				
5	Hydraulic Production Plant—Pumped Storage				
6	Other Production Plant				
7	Transmission Plant				
8	Distribution Plant				
9	General Plant	2,047			2,047
10	Common Plant—Electric				
11	TOTAL	2,047			2,047

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1985

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 accounts. 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	Miscellaneous Income Deductions		
2	A/C 426.1 - Other Deductions - Donations		50
3			
4	A/C 431 - Other Interest Expense		
5	1% per month outstanding CVPSC Balance	7,526	
6	Interest on short-term borrowing	70,126	
7			77,652
8			
9	Interest rates on short-term debt ranged from 8.55% to 12.375%		
10	during 1984.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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 formal cases before a regulatory body, or cases in which such a body was a party.

2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

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 Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1	PSB Docket 4701: VPIRG - Seabrook		37,976	37,976	-0-
2					
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46	TOTAL		37,976	37,976	-0-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

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. The totals of columns (e), (i), (k), and (l) must agree with the totals shown at the bottom of page 223 for Account 186.

5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.

6. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (k)	Deferred in Account 186, End of Year (l)	Line No.
	928	37,976	--	--	--	-0-	1
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		37,976					46

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) projects initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
  (1) Generation
    a. Hydroelectric
      i. Recreation, fish, and wildlife
      ii. Other hydroelectric
    b. Fossil-fuel steam
    c. Internal combustion or gas turbine
    d. Nuclear
    e. Unconventional generation
    f. Siting and heat rejection
  (2) System Planning, Engineering and Operation
  (3) Transmission
    a. Overhead
    b. Underground
  (4) Distribution
  (5) Environment (other than equipment)
  (6) Other *(Classify and include items in excess of $5,000.)*
  (7) Total Cost Incurred

B. Electric R, D & D Performed Externally
  (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others *(Classify)*
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, *Construction Work in Progress,* first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, *Research, Development, and Demonstration Expenditures,* outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to *Utility Departments, Construction, Plant Removals, and Other Accounts,* and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	9,372		
4	Transmission			
5	Distribution			
6	Customer Accounts			
7	Customer Service and Informational			
8	Sales			
9	Administrative and General	4,021		
10	TOTAL Operation *(Enter Total of lines 3 thru 9)*	13,393		
11	Maintenance			
12	Production			
13	Transmission			
14	Distribution			
15	Administrative and General			
16	TOTAL Maintenance *(Enter Total of lines 12 thru 15)*			
17	Total Operation and Maintenance			
18	Production *(Enter Total of lines 3 and 12)*	9,372		
19	Transmission *(Enter Total of lines 4 and 13)*			
20	Distribution *(Enter Total of lines 5 and 14)*			
21	Customer Accounts *(Transcribe from line 6)*			
22	Customer Service and Informational *(Transcribe from line 7)*			
23	Sales *(Transcribe from line 8)*			
24	Administrative and General *(Enter Total of lines 9 and 15)*	4,021		
25	TOTAL Operation and Maintenance *(Total of lines 18 thru 24)*	13,393	1,500	14,893
26	Gas			
27	Operation			
28	Production—Manufactured Gas			
29	Production—Natural Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation *(Enter Total of lines 28 thru 37)*			
39	Maintenance			
40	Production—Manufactured Gas			
41	Production—Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maintenance *(Enter Total of lines 40 thru 46)*			

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
48	Total Operation and Maintenance			
49	Production—Manufactured Gas *(Enter Total of lines 28 and 40)*			
50	Production—Natural Gas (Including Expl. and Dev.) *(Total of lines 29 and 41)*			
51	Other Gas Supply *(Enter Total of lines 30 and 42)*			
52	Storage, LNG Terminaling and Processing *(Total of lines 31 and 43)*			
53	Transmission *(Enter Total of lines 32 and 44)*			
54	Distribution *(Enter Total of lines 33 and 45)*			
55	Customer Accounts *(Transcribe from line 34)*			
56	Customer Service and Informational *(Transcribe from line 35)*			
57	Sales *(Transcribe from line 36)*			
58	Administrative and General *(Enter Total of lines 37 and 46)*			
59	TOTAL Operation and Maint. *(Total of lines 49 thru 58)*			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. *(Total of lines 25, 59, and 61)*	13,393	1,500	14,893
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	6,364	717	7,081
66	Gas Plant			
67	Other			
68	TOTAL Construction *(Enter Total of lines 65 thru 67)*			
69	Plant Removal (By Utility Department)			
70	Electric Plant			
71	Gas Plant			
72	Other			
73	TOTAL Plant Removal *(Enter Total of lines 70 thru 72)*			
74	Other Accounts *(Specify)*:			
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89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts			
96	TOTAL SALARIES AND WAGES	19,757	2,217	21,974

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	183,165
3	Steam		22	Sales for Resale	
4	Nuclear		23	Energy Furnished Without Charge	
5	Hydro–Conventional		24	Energy Used by the Company (Excluding Station Use):	
6	Hydro–Pumped Storage		25	Electric Department Only	
7	Other		26	Energy Losses:	
8	Less Energy for Pumping		27	Transmission and Conversion Losses	
9	Net Generation *(Enter Total of lines 3 thru 8)*		28	Distribution Losses	
10	Purchases	183,165	29	Unaccounted for Losses	
11	Interchanges:		30	TOTAL Energy Losses	
12	In (gross)		31	Energy Losses as Percent of Total on Line 19 ______ %	
13	Out (gross)		32	TOTAL *(Enter Total of lines 21, 22, 23, 25, and 30)*	183,165
14	Net Interchanges *(Lines 12 and 13)*				
15	Transmission for/by Others (Wheeling)				
16	Received ______ MWh				
17	Delivered ______ MWh				
18	Net Transmission *(Lines 16 and 17)*				
19	TOTAL *(Enter Total of lines 9, 10, 14, and 18)*	183,165			

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.

2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system. Show monthly peak *including* such emergency deliveries in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.

3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).

4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.

5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

Name of System:

Line No.	Month (a)	MONTHLY PEAK: Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) *(See Instr. 4)* (g)
33	January	34.3					17,278
34	February	34.3					15,836
35	March	34.3					15,168
36	April	35.3					17,376
37	May	37.3					14,857
38	June	37.3					16,654
39	July	38.3					13,651
40	August	34.3					13,440
41	September	38.3					14,596
42	October	37.3					13,961
43	November	35.8					15,382
44	December	36.6					14,966
45	TOTAL						183,165

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

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 on 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 of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
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 (b)	Plant Name (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)		
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)		
6	Net Peak Demand on Plant—MW (60 minutes)		
7	Plant Hours Connected to Load		
8	Net Continuous Plant Capability (Megawatts)		
9	When Not Limited by Condenser Water		
10	When Limited by Condenser Water		
11	Average Number of Employees		
12	Net Generation, Exclusive of Plant Use — KWh		
13	Cost of Plant:		
14	Land and Land Rights		
15	Structures and Improvements		
16	Equipment Costs	INTENTIONALLY BLANK	
17	Total Cost		
18	Cost per KW of Installed Capacity (Line 5)		
19	Production Expenses:		
20	Operation Supervision and Engineering		
21	Fuel		
22	Coolants and Water (Nuclear Plants Only)		
23	Steam Expenses		
24	Steam From Other Sources		
25	Steam Transferred (Cr.)		
26	Electric Expenses		
27	Misc. Steam (or Nuclear) Power Expenses		
28	Rents		
29	Maintenance Supervision and Engineering		
30	Maintenance of Structures		
31	Maintenance of Boiler (or Reactor) Plant		
32	Maintenance of Electric Plant		
33	Maint. of Misc. Steam (or Nuclear) Plant		
34	Total Production Expenses		
35	Expenses per Net KWh		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit: (Coal—tons of 2,000 lb.)(Oil—barrels of 42 gals.)(Gas—Mcf)(Nuclear—indicate)		
38	Quantity (Units) of Fuel Burned		
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) *(Give unit if nuclear)*		
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year		
41	Average Cost of Fuel per Unit Burned		
42	Avg. Cost of Fuel Burned per Million Btu		
43	Avg. Cost of Fuel Burned per KWh Net Gen.		
44	Average Btu per KWh Net Generation		

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.

10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 26 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.

11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.

12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name (d)	Plant Name (e)	Plant Name (f)	Line No.
			1
			2
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

Average Annual Heat Rates and Corresponding Net MWh Output for Most Efficient Generating Units

1. Report only the most efficient generating units (not to exceed 10 in number) which were operated at annual capacity factors of 50 percent or higher. List only unit type installations, i.e., single boiler serving one turbine-generator. It is not necessary to report single unit plants on this page. Do not include non-condensing or automatic extraction-type turbine units operated for processing steam and electric power generation.

2. Annual Unit Capacity Factor =

$$\frac{\text{Net Generation—Kwh:}}{\text{Unit KW. Capacity (as included in plant total—line 5, p. 402)} \times 8{,}760 \text{ hours}}$$

3. Report annual system heat rate for total conventional steam-power generation and corresponding net generation (line 11).

4. Compute all heat rates on this page and also on pages 403 and 404 on the basis of total fuel burned, including burner lighting and banking fuel.

Line No.	Plant Name (a)	Unit No. (b)	MW (Generator Rating at Maximum Hydrogen Pressure) (c)	Btu Per Net MWh (d)	Net Generation Thousand MWh (e)	Kind of Fuel (f)
1						
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10						
	Total System Steam Plants					
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(Next Page is 406)

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).

2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.

3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.

4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. ______ Plant Name ______ (b)	FERC Licensed Project No. ______ Plant Name ______ (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Type of Plant Construction (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Capacity (Generator Name Plate Ratings in MW)		
6	Net Peak Demand on Plant—Megawatts (60 minutes)		
7	Plant Hours Connected to Load		
8	Net Plant Capability (In megawatts)		
9	(a) Under the Most Favorable Oper. Conditions		
10	(b) Under the Most Adverse Oper. Conditions		
11	Average Number of Employees		
12	Net Generation, Exclusive of Plant Use – KWh		
13	Cost of Plant:		
14	Land and Land Rights		
15	Structures and Improvements		
16	Reservoirs, Dams, and Waterways		
17	Equipment Costs		
18	Roads, Railroads, and Bridges		
19	TOTAL Cost *(Enter Total of lines 14 thru 18)*	INTENTIONALLY BLANK	
20	Cost per KW of Installed Capacity (Line 5)		
21	Production Expenses:		
22	Operation Supervision and Engineering		
23	Water for Power		
24	Hydraulic Expenses		
25	Electric Expenses		
26	Misc. Hydraulic Power Generation Expenses		
27	Rents		
28	Maintenance Supervision and Engineering		
29	Maintenance of Structures		
30	Maintenance of Reservoirs, Dams, and Waterways		
31	Maintenance of Electric Plant		
32	Maintenance of Misc. Hydraulic Plant		
33	Total Production Expenses *(Total lines 22 thru 32)*		
34	Expenses per Net KWh		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 1984

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. ____ Plant Name ____ (d)	FERC Licensed Project No. ____ Plant Name ____ (e)	FERC Licensed Project No. ____ Plant Name ____ (f)	Line No.
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			2
			3
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. ____ Plant Name ____ (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total Installed Capacity (Generator Name Plate Ratings in MW)	
5	Net Peak Demand on Plant—Megawatts (60 minutes)	
6	Plant Hours Connected to Load While Generating	
7	Net Plant Capability (In megawatts):	
8	Average Number of Employees	
9	Generation Exclusive of Plant Use — KWh	
10	Energy Used for Pumping — KWh	
11	Net Output for Load (line 9 minus line 10) — KWh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	TOTAL Cost *(Enter Total of lines 13 thru 19)*	
21	Cost per KW of Installed Capacity *(line 20 ÷ line 4)*	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Pumped Storage Expenses	
26	Electric Expenses	
27	Miscellaneous Pumped Storage Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Miscellaneous Pumped Storage Plant	
34	Production Exp. Before Pumping Exp. *(Enter Total of lines 23 thru 33)*	
35	Pumping Expenses	
36	Total Production Expenses *(Enter Total of lines 34 and 35)*	
37	Expenses per KWh *(Enter result of line 36 divided by line 9)*	

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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1984

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on line 35 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed, leave lines 35, 36 and 37 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other sources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier, contract number, and date of contract.

FERC Licensed Project No. ______ Plant Name ______ (c)	FERC Licensed Project No. ______ Plant Name ______ (d)	FERC Licensed Project No. ______ Plant Name ______ (e)	Line No.
			1
			2
			3
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			37

Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, page 403.
4. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity-Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 Min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost per MW Inst. Capacity (g)	Production Expenses: Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)
1												
2												
3												
4												
5												
6												
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Name of Respondent	This Report Is:	Date of Report	Year of Report
VEG&T	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 84

CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

Give below the information called for concerning changes in electric generating plant capacities during the year.

A. Generating Plants or Units Dismantled, Removed from Service, Sold, or Leased to Others During Year

1. State in column (b) whether dismantled, removed from service, sold, or leased to another. Plants removed from service include those not maintained for regular or emergency service.

2. In column (f), give date dismantled, removed from service, sold, or leased to another. Designate complete plants as such.

Line No.	Name of Plant (a)	Disposition (b)	Installed Capacity (In megawatts) Hydro (c)	Steam (d)	(Other) (e)	Date (f)	If Sold or Leased to Another, Give Name and Address of Purchaser or Lessee (g)
1							
2							
3							
4							
5							
6							
7							

B. Generating Units Scheduled for or Undergoing Major Modifications

Line No.	Name of Plant (a)	Character of Modification (b)	Installed Plant Capacity After Modification (In megawatts) (c)	Estimated Dates of Construction Start (d)	Completion (e)
8					
9					
10					
11					
12					
13					
14					

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Installed Capacity (In megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
15	North Hartland Dam	Hydro	4		5/83	4/85
16	North Hartland, Vermont					
17						
18						
19						
20						
21						

D. New Units in Existing Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Unit No. (c)	Size of Unit (In megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22						
23						
24						
25						
26						
27						
28						

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19___

STEAM-ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show unit type installation, boiler, and turbine-generator, on same line.
3. Exclude plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any generating plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing

Line No.	Name of Plant	Location of Plant	Boilers (*Include both ratings for the boiler and the turbine-generator of dual-rated installations*)				
			Number and Year Installed	Kind of Fuel and Method of Firing	Rated Pressure (In psig)	Rated Steam Temperature (*Indicate reheat boilers as 1050/1000*)	Rated Max. Continuous M lbs. Steam per Hour
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
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INDEX

INDEX (Continued)

Vermont Electric Generation and Transmission Dec. 31, 1984

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INDEX (Continued)

INDEX (Continued)

INDEX (Continued)

FINANCIAL STATEMENTS AND AUDITORS' REPORT

TAUNTON MUNICIPAL LIGHTING PLANT

December 31, 1984

Alexander Grant
& COMPANY

FINANCIAL STATEMENTS AND AUDITORS' REPORT

TAUNTON MUNICIPAL LIGHTING PLANT

December 31, 1984

C O N T E N T S

Alexander Grant
& COMPANY
CERTIFIED PUBLIC ACCOUNTANTS

MEMBER FIRM
GRANT THORNTON INTERNATIONAL

Municipal Light Commission
of the City of Taunton
Taunton, Massachusetts

We have examined the balance sheet of Taunton Municipal Lighting Plant (a department of the City of Taunton) as of December 31, 1984, and the related statements of earnings, surplus and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

As discussed in note F, Taunton Municipal Lighting Plant records pension expense based on a formula determined by the Town; whereas, generally accepted accounting principles require the use of actuarial methods in determining annual pension expense.

In our opinion, except for the effect on the financial statements of the accounting policy discussed in the second paragraph, the financial statements referred to above present fairly the financial position of Taunton Municipal Lighting Plant at December 31, 1984, and the results of its operations and changes in its financial position for the year then ended, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Alexander Grant + Company

Boston, Massachusetts
March 14, 1985

99 HIGH STREET BOSTON, MA 02110 (617) 357-5787

Taunton Municipal Lighting Plant

BALANCE SHEET

December 31, 1984

ASSETS

UTILITY PLANT - AT COST		
Plant in service	$57,662,324	
Less accumulated depreciation (note A2)	27,824,183	
Net utility plant in service		$29,838,141
Construction work in progress (note D)		3,437,120
Total utility plant		33,275,261
DEPRECIATION FUND		
Cash and cash equivalents		5,025,233
CURRENT ASSETS		
Cash (note E)		1,236,244
Customer deposits (note E)		
Principal fund		183,608
Interest fund		34,921
Accounts receivable	5,899,854	
Less allowance for doubtful receivables	476,780	5,423,074
Materials and supplies inventory (note A4)		2,962,020
Prepaid insurance		28,272
Total current assets		9,868,139
		$48,168,633

The accompanying notes are an integral part of this statement.

LIABILITIES AND SURPLUS

SURPLUS		
Appropriated surplus		
Loans repayment	$11,132,000	
Construction repayment	32,434	
	11,164,434	
Unappropriated surplus	10,201,858	
Total surplus		$21,366,292
LONG-TERM DEBT (note C)		
Bonds payable	22,055,710	
Less current maturities	525,000	
Total long-term debt		21,530,710
CURRENT LIABILITIES		
Accounts payable	2,663,323	
Customer deposits	183,608	
Current maturities of long-term debt	525,000	
Accrued liabilities		
Interest	737,319	
Compensated absences	1,080,403	
Payroll	81,978	
Total current liabilities		5,271,631
COMMITMENTS (note D)		
		$48,168,633

Taunton Municipal Lighting Plant

STATEMENT OF EARNINGS

Year ended December 31, 1984

Operating revenues		
Sales of electricity		
Commercial and industrial	$15,984,368	
Residential	12,060,350	
Sales for resale (note D)	16,379,380	
Municipal	1,822,761	$46,246,859
Other operating revenues		83,613
Total operating revenues		46,330,472
Operating expenses		
Power production	33,742,151	
Transmission and distribution	1,293,630	
Customer accounts	673,354	
Administrative and general	3,192,823	
Depreciation (note A2)	2,204,616	
Total operating expenses		41,106,574
Earnings from operations		5,223,898
Other income (expense)		
Interest income	299,002	
Interest expense on bonds	(1,717,672)	
Other	24,046	
Total other income (expense)		(1,394,624)
NET EARNINGS BEFORE PROVISION FOR PAYMENT IN LIEU OF TAXES		3,829,274
Provision for payment to the City of Taunton in lieu of taxes (note B)		1,030,000
EXCESS NET EARNINGS AFTER PAYMENT TO CITY OF TAUNTON		$ 2,799,274

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

STATEMENT OF SURPLUS

Year ended December 31, 1984

	Appropriated Surplus		
	Loans Repayment	Construction Repayment	Unappropriated Surplus
Balance at January 1, 1984	$10,637,000	$32,434	$ 7,897,584
ADD OR (DEDUCT)			
Transfer from unappropriated surplus of bond payments during year	495,000		(495,000)
Excess net earnings after payment to City of Taunton			2,799,274
Balance at December 31, 1984	$11,132,000	$32,434	$10,201,858

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

STATEMENT OF CHANGES IN FINANCIAL POSITION

Year ended December 31, 1984

Sources of working capital	
From operations	
Net earnings before payment in lieu of taxes	$3,829,274
Charges (credits) to earnings not using (providing) working capital	
Depreciation of utility plant (note A2)	2,204,616
Amortization of bond premium	(3,354)
Funds from operations before payment in lieu of taxes	6,030,536
Provision for payment to City in lieu of taxes (note B)	1,030,000
Net working capital provided from operations	5,000,536
Applications of working capital	
Current maturities of long-term debt (note C)	525,000
Utility plant additions - net	2,326,823
Increase in depreciation fund	1,815,033
Total applications of working capital	4,666,856
INCREASE IN WORKING CAPITAL	333,680
Working capital at January 1, 1984	4,262,828
Working capital at December 31, 1984	$4,596,508
Changes in components of working capital	
Increase (decrease) in current assets	
Cash	$ (482,582)
Customer deposits	21,187
Accounts receivable - net	282,675
Inventory	254,672
Prepaid insurance	(8,277)
	67,675
(Increase) decrease in current liabilities	
Accounts payable	488,257
Customer deposits	(15,250)
Current maturities of long-term debt	(30,000)
Accrued liabilities	(177,002)
	266,005
INCREASE IN WORKING CAPITAL	$ 333,680

The accompanying notes are an integral part of this statement.

Taunton Municipal Lighting Plant

NOTES TO FINANCIAL STATEMENTS

December 31, 1984

NOTE A - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

1. Rates

   Rates charged by the Plant are not subject to the approval of regulatory agencies. Pursuant to state laws, rates must be such that the resulting net earnings before payment to the city, less bond payments, do not exceed 8% of the cost of utility plant. During 1984, the Plant's earnings, less bond payments, amounted to 5.8% of utility plant.

2. Depreciation

   Pursuant to state laws, depreciation is calculated as a percentage of depreciable property at January 1. Depreciation was computed at 4% of the cost of depreciable property for 1983 and 1984.

   The amount transferred from the operating fund to the depreciation fund during the year was $4,369,616.

   Depreciation fund cash is used in accordance with state laws for replacements and additions to the electric plant in service.

3. Pension Plan

   Substantially all employees of the Plant are covered by a contributory pension plan administered by the City of Taunton in conformity with State Retirement Board requirements. In addition, the Lighting Plant has a separate Employees Retirement Trust for the financing of future pension premiums. At December 31, 1984, the Retirement Trust had net assets of approximately $2,463,776. The Plant contributed approximately $1,512,378 for pensions in 1984, which included $700,000 to the separate Retirement Trust.

4. Inventory

   Materials and supplies inventory is carried at cost, principally on the average cost and first-in, first-out methods.

Taunton Municipal Lighting Plant

NOTES TO FINANCIAL STATEMENTS - CONTINUED

December 31, 1984

NOTE B - CONTRIBUTION TO THE CITY OF TAUNTON IN LIEU OF TAXES

By vote of the Municipal Light Commission, the Plant contributed $1,030,000 in 1984 to the City of Taunton in lieu of taxes. All contributions to the City are voted by the Municipal Light Commission and are voluntary.

NOTE C - LONG-TERM DEBT

Long-term debt at December 31, 1984, is comprised of the following:

Electric loan, Act of 1969 Interest rate - various rates from 7% to 8.5% dated February 1, 1976. Interest payable February 1 and August 1. Due serially from February 1, 1977 to February 1, 2006	$21,840,000
Unamortized premium	70,710
Electric loan, Act of 1963 Interest rate 3.1% dated August 15, 1965. Interest payable August 15 and February 15. Due serially from August 15, 1966 to August 15, 1985	45,000
Electric loan, Act of 1963 Interest rate 3% dated January 1, 1965. Interest payable January 1 and July 1. Due serially from January 1, 1966 to January 1, 1985	100,000
	22,055,710
Less current maturities	525,000
Total long-term debt	$21,530,710

NOTE C - LONG-TERM DEBT - Continued

Annual maturities of long-term debt are:

	3% Bonds	3.1% Bonds	7% - 8.5% Bonds	Total
1985	$100,000	$45,000	$ 380,000	$ 525,000
1986			410,000	410,000
1987			445,000	445,000
1988			480,000	480,000
1989			520,000	520,000
1990-2006			19,605,000	19,605,000
Bond premium			70,710	70,710
	$100,000	$45,000	$21,910,710	$22,055,710

NOTE D - COMMITMENTS

Interconnection Agreement

The City of Taunton, acting by vote of its Municipal Lighting Plant Commission, has entered into an agreement with Montaup Electric Company ("Montaup"), dated July 31, 1970, as amended, concerning interconnection of electrical operations, purchase and sale of kilowatt capacity, and construction by Taunton of a generating unit of approximately 110 megawatt capability. The agreement is for a period of twelve years following the commencement of operations of Unit No. 9 on December 1, 1975. Under the interconnection agreement, the City agrees to sell and Montaup agrees to purchase all capacity of Unit No. 9 not utilized by the City with a maximum not to exceed 95 megawatts in the first year of operation and on a declining scale in subsequent years. It is estimated that by 1986 or 1987 Montaup will have purchased the maximum capacity allowed by law for sale to that utility. The Plant credited to sales for resale $15,104,852 of capacity and energy charges billed to Montaup Electric Company in 1984 for its share of power under the interconnection agreement. This agreement includes a provision that Taunton will purchase 8.2163% of the capacity and associated energy from Montaup's Somerset No. 6 generating unit for the period November 1, 1978 through October 31, 1984, and 1.7123% of the capacity and associated energy from the Canal No. 2 generating unit, 50% of which is owned by Montaup, for the period November 1, 1978 through October 31, 1982. The agreement for capacity and associated energy purchases from Canal No. 2 has been extended through October 31, 1987.

NOTE D - COMMITMENTS - Continued

Entitlements

The Plant is a joint owner of the Seabrook Units 1 and 2 nuclear generating station located in Seabrook, New Hampshire. The lead participant in the project is Public Service Company of New Hampshire (PSNH). The Plant's ownership share is .10034%. Expenditures of $3,029,348 through December 31, 1984, are included in the construction work in progress account. Several participants in the Seabrook Units have been successful in effectively cancelling Unit 2. The Plant is unable to predict whether any action will be ordered by the New Hampshire Public Utilities Commission or what effect such action, or any financing difficulties of PSNH or any other participant, may have on the cost of completion of Unit 1.

Assuming that construction will continue, it is estimated that Unit 1 will be completed in April, 1987. The Plant's latest estimates put its share of the cost to complete Unit 1 at approximately $1,000,000.

NOTE E - CASH

Municipal Lighting Plant cash is in the custody of the City of Taunton Treasurer and is commingled with other city funds. The City maintains the cash in interest bearing accounts and credits the interest earned each year to the Plant's account.

NOTE F - DEPARTURE FROM GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Pension expense is not recorded in accordance with generally accepted accounting principles which require, as a minimum, an annual provision equal to the total of normal costs of present employees under the plan, an amount equivalent to interest on any unfunded prior service costs, and a provision for vested benefits.

Instead, the Plant's pension expense is based on the current year contributions to the City's retirement fund and the Plant's Retirement Trust. The contribution to the City's retirement fund is based on the projected benefits to be paid during the year, while the contribution to the Retirement Trust is a straight-line funding of $350,000 per year for ten years. Due to the availability of funds, the Plant contributed $700,000 to the Retirement Trust in 1984.

The effect on the accompanying financial statements of this departure from generally accepted accounting principles has not been determined.

SUPPLEMENTAL INFORMATION

AUDITORS' REPORT ON SUPPLEMENTAL INFORMATION

Taunton Municipal Lighting Plant

Our examination was made for the purpose of forming an opinion on the basic financial statements taken as a whole of Taunton Municipal Lighting Plant for the year ended December 31, 1984, which is presented in the preceding section of this report. The supplemental information presented hereinafter is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the audit procedures applied in the examination 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.

Alexander Grant + Company

Boston, Massachusetts
March 14, 1985

Taunton Municipal Lighting Plant

UTILITY PLANT

Year ended December 31, 1984

	Balance January 1, 1984
Utility plant in service	
Steam production plant	
Land and land rights	$ 245,509
Structures and improvements	5,805,070
Boiler plant equipment	14,805,610
Turbo-generator units	13,802,920
Accessory electric equipment	2,563,912
Miscellaneous power plant equipment	427,268
Total steam production plant	37,650,289
Other production plant	
Fuel holders, producers and accessories	507,964
Generators	83,407
Accessory electric equipment	402,423
Total other production plant	993,794
Transmission plant	
Land and land rights	217,807
Clearing land and rights of way	28,901
Structures and improvements	129,489
Station equipment	2,333,541
Towers and fixtures	859,446
Poles and fixtures	304,605
Overhead conductors and devices	309,322
Underground conduit	3,104
Underground conductors	6,113
Total transmission plant	4,192,328
Distribution plant	
Land and land rights	189,056
Structures and improvements	103,341
Station equipment	1,686,072
Poles, towers and fixtures	1,984,895
Overhead conductors and devices	1,897,307
Underground conduit	1,398,681
Underground conductors and devices	1,483,328
Line transformers	1,169,779
Services	280,778
Meters	1,020,182
Street lighting and signal system	620,974
Total distribution plant	11,834,393
Forward	54,670,804

Also Available On Aperture Card

TI APERTURE CARD

Additions	Retirements	Balance December 31, 1984	Accumulated Depreciation December 31, 1984	Net Book Value December 31, 1984
		$ 245,509		$ 245,509
$ 868,972		6,674,042	$ 3,622,677	3,051,365
487,888		15,293,498	7,045,246	8,248,252
84,046		13,886,966	4,899,816	8,987,150
1,902		2,565,814	1,762,481	803,333
3,154		430,422	119,008	311,414
1,445,962		39,096,251	17,449,228	21,647,023
		507,964	156,654	351,310
		83,407	25,669	57,738
		402,423	124,550	277,873
		993,794	306,873	686,921
		217,807		217,807
		28,901		28,901
		129,489	29,192	100,297
2,994		2,336,535	550,462	1,786,073
		859,446	261,069	598,377
		304,605	77,737	226,868
		309,322	68,628	240,694
		3,104	749	2,355
		6,113	1,120	4,993
2,994		4,195,322	988,957	3,206,365
(37,370)		151,686		151,686
2,800		106,141	99,020	7,121
6,546		1,692,618	1,479,240	213,378
92,905		2,077,800	1,764,331	313,469
116,700		2,014,007	971,799	1,042,208
22,551		1,421,232	1,091,202	330,030
27,063		1,510,391	930,098	580,293
75,070	$13,062	1,231,787	763,126	468,661
20,647		301,425	83,041	218,384
45,453		1,065,635	720,453	345,182
50,575		671,549	363,749	307,800
422,940	13,062	12,244,271	8,266,059	3,978,212
1,871,896	13,062	56,529,638	27,011,117	29,518,521

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Taunton Municipal Lighting Plant

UTILITY PLANT - CONTINUED

Year ended December 31, 1984

	Balance January 1, 1984
Forwarded	$54,670,804
General plant	
Land and land rights	35,691
Structures and improvements	281,965
Office furniture and equipment	122,304
Transportation equipment	562,092
Stores equipment	1,740
Tools, shop and garage equipment	13,093
Laboratory equipment	14,888
Power operated equipment	27,271
Communication equipment	86,858
Miscellaneous equipment	15,649
Total general plant	1,161,551
Less contribution in aid of construction	(64,986)
Total utility plant in service	55,767,369
Construction work in progress	3,030,752
	$58,798,121

Additions	Retirements	Balance December 31, 1984	Accumulated Depreciation December 31, 1984	Net Book Value December 31, 1984
$1,871,896	$13,062	$56,529,638	$27,011,117	$29,518,521
		35,691		35,691
		281,965	246,757	35,208
28,170		150,474	67,434	83,040
24,411	16,460	570,043	413,700	156,343
		1,740	1,740	
		13,093	13,093	
		14,888	11,492	3,396
		27,271	17,298	9,973
		86,858	27,929	58,929
		15,649	13,623	2,026
52,581	16,460	1,197,672	813,066	384,606
		(64,986)		(64,986)
1,924,477	29,522	57,662,324	27,824,183	29,838,141
406,368		3,437,120		3,437,120
$2,330,845	$29,522	$61,099,444	$27,824,183	$33,275,261

Taunton Municipal Lighting Plant

OPERATING EXPENSES

Year ended December 31, 1984

POWER PRODUCTION EXPENSES		
Operation		
Supervision and engineering	$ 251,367	
Fuel	17,911,817	
Labor and expenses	940,734	$19,103,918
Maintenance		
Supervision and engineering	81,281	
Structures	46,408	
Boiler plant	994,781	
Electric plant	731,272	
Miscellaneous	18,711	1,872,453
Purchased power		12,765,780
Total power production expenses		33,742,151
TRANSMISSION AND DISTRIBUTION EXPENSES		
Operation		
Supervision and engineering	205,183	
Labor	161,929	
Supplies and expenses	21,601	
Meter expenses	31,883	
Customer installation	1,345	
Street lighting and signal systems	31,832	
Miscellaneous	149,434	603,207
Maintenance		
Lines - electric	498,840	
Lines - steam	939	
Street lighting and signal systems	36,852	
Meters	54,118	
Structures and equipment	15,941	
Line transformers	29,433	
Station equipment	43,592	
Miscellaneous	10,708	690,423
Total transmission and distribution expenses		1,293,630
Forward		35,035,781

Taunton Municipal Lighting Plant

OPERATING EXPENSES - CONTINUED

Year ended December 31, 1984

Forwarded		$35,035,781
CUSTOMER ACCOUNTS EXPENSES		
Operation		
Meter reading labor and expenses	$ 105,527	
Accounting and collecting expenses	505,715	
Uncollectible accounts	42,000	
Advertising expense	20,112	
Total customer accounts expenses		673,354
ADMINISTRATIVE AND GENERAL EXPENSES		
Operation		
Administrative and general salaries	312,120	
Office supplies and expenses	139,918	
Outside services employed	84,107	
Property insurance	102,657	
Injuries and damages	182,577	
Employee pensions and benefits	2,129,569	
Miscellaneous general expenses	51,224	
Transportation expenses	111,938	
Regulatory commission expense	18,426	3,132,536
Maintenance		
General plant		60,287
Total administrative and general expenses		3,192,823
DEPRECIATION EXPENSE		2,204,616
		$41,106,574

OMB No. 1905-0136
Expires 4-30-85

ANNUAL REPORT OF PUBLIC ELECTRIC UTILITIES

This report is mandatory under the Federal Energy Administration Act of 1974 (P.L. 93-275). Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. None of the information reported on this form is deemed to be confidential, since it is reported by public bodies and concerns their exercise of public functions.

Exact Legal Name of Respondent	Report Is For Fiscal Year Ending
TOWN OF HUDSON LIGHT AND POWER DEPT.	DECEMBER 31, 1984

EIA-412 (6-82)

Form Approved
OMB No. 1905-0136
Expires 4-30-85

U.S. DEPARTMENT OF ENERGY

Washington, D.C. 20585

INSTRUCTIONS FOR FILING ANNUAL REPORT OF PUBLIC ELECTRIC UTILITIES

GENERAL INFORMATION

I. Purpose

This form is a requirement (P.L. 93-275). It is designed to collect information on municipal electrical utilities owned or operated by municipalities in the United States and its possessions. Municipality is defined as a city, county, irrigation district, drainage district, or other political subdivision as agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing or distributing power. [41 Stat 1064; 49 Stat 838; 16 U.S.C. 796(7)].

II. Who Must Submit

Each municipality engaged in the generation, transmission, or distribution of electricity, and which has been notified by the Department of Energy, must submit this form.

III. What and Where to Submit

(a) Submit an original and three copies of Form EIA-412, together with any required attachments, to:

U.S. Department of Energy
Energy Information Administration (EI-541)
Forrestal Building, Mail Station BE-079
Washington, D.C. 20585

(b) If you publish financial and operating statements of your utility department, attach three copies of such statements to this report.

(c) Retain a copy of this form for your files.

IV. When To Submit

Submit this form on or before the last day of the third month following the close of your established fiscal year. For example, if your fiscal year ends March 31, this report is due on or before June 30.

V. Confidentiality

None of the information reported on this form is deemed to be confidential, since it is reported by public bodies and concerns their exercise of public functions.

VI. Sanctions

The timely submission of Form EIA-412 by a utility required to report is a mandatory requirement. Late filing, failure to file, failure to keep records, or failure otherwise to comply with these instructions may result in criminal fines, civil penalties, and other sanctions as provided by law.

GENERAL INSTRUCTIONS

I. Account numbers and titles used in this form relate to account numbers and titles in the Uniform System of Accounts Prescribed for Public Utilities and Licensees. The use of the Uniform System of Accounts for the reporting of data by municipalities is preferred but not required, subject to the Provisions of the Federal Power Act (18 CFR 101).

II. Use Part XXVI, Footnote Data, to footnote any entry made to Parts III through XXV.

III. Enter amounts in whole numbers only.

IV. Indicate negative amounts by enclosing the figures in parentheses ( ).

V. When making revisions, resubmit only those pages that have been changed from the original. Include with your resubmission Part I, Identification, and Part II, Attestation.

VI. Enter "Not Applicable" where the information requested is not applicable to your system.

VII. Provide a supplemental statement further explaining accounts or parts as necessary. Attach the supplemental statement to the page being supplemented. Provide the appropriate identification information, including the title of the page and the page number supplemented.

DEFINITIONS

(a) Advances from Municipality — The amount of loans and advances made by the municipality or its other departments to the utility department when such loans and advances are subject to repayment but not subject to current settlement.

(b) Advances to Municipality — The amount of loans and advances made by the utility department to the municipality or its other departments when such loans or advances are subject to repayment but not subject to current settlement.

(c) Authorized Cash Distribution to Municipality — The authorized cash distributions to the municipality from the earned surplus of the utility department.

(d) Constructive Surplus or Deficit — The amounts representing the exchange of services, supplies, etc., between the utility department and the municipality and its other departments without charge or at a reduced charge. Charges to this account include utility and other services, supplies, etc., furnished by the utility department to the municipality or its other departments without charge, or the amount of the reduction if furnished at a reduced charge. Credits to the account consist of services, supplies, office space, etc., furnished by the municipality to the utility department without charge or the amount of the reduction if furnished at a reduced charge.

(e) Electric Plant Acquisition Adjustment — The difference between (a) the cost to the respondent utility of electric plant acquired as an operating unit or system by purchase and (b) the depreciated original cost, estimated if not known, of such property.

(f) Extraordinary Income (Deductions) — Those items related to transactions of a nonrecurring nature which are not typical or customary business activities of the utility and which would significantly distort the current year's net income if reported other than as extraordinary items.

(g) Investment of Municipality — The investment of the municipality in its utility department, when such investment is not subject to cash settlement on demand or at a fixed future time. Include the cost of debt-free utility plant constructed or acquired by the municipality and made available for the use of the utility department, cash transferred to the utility department for working capital, and other expenditures of an investment nature.

DEFINITIONS (Continued)

(h) Municipality – (As defined in section 3, paragraph (7) of the Federal Power Act, P.L. 66-280 as amended) A city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power [41 stat. 1064; 49 stat. 838; 16 U.S.C. 796(7)]

(i) Payables to Municipality – The amounts payable by the utility department to the municipality or its other departments which are subject to current settlement.

(j) Receivables from Municipality – All charges by the utility department against the municipality or its other departments which are subject to current settlement.

(k) Retained Earnings – The balance, either debit or credit, of appropriated or unappropriated retained earnings of the utility department arising from earnings.

SPECIFIC INSTRUCTIONS

Item	Instruction
All	Refer to the form. All items are self-explanatory.

ANNUAL REPORT OF PUBLIC ELECTRIC UTILITIES

PART I: IDENTIFICATION

01 Exact Legal Name of Respondent Town of Hudson Light & Power Dept.	02 Report is for Fiscal Year Ending *(Mo, Da, Yr)* December 31, 1984
03 Previous Name and Date of Change *(If name changed during year)*	
04 Address of Principal Business Office at End of Year *(Street, City, State, Zip Code)* 49 Forest Ave. Hudson, MA 01749	
05 Name of Contact Person Horst Huehmer	06 Title of Contact Person Manager
07 Address of Contact Person *(Street, City, State, Zip Code)* 49 Forest Ave. Hudson, MA 01749	

08 Telephone of Contact Person, Including Area Code 617-568-8736	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 3/31/85

11 State the Classes of Utility and Other Services Furnished by Respondent During the Year

Municipal - Lighting and Power

PART II: CERTIFICATION

The undersigned 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 calendar or other established fiscal year stated above.

01 Name Horst Huehmer	03 Signature	04 Date Signed *(Mo, Da, Yr)* 4/1/85
02 Title Manager		

Title 18, U.S.C. 1001, makes it a crime for any person 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)	Report Year Ending (Mo, Da, Yr)
Hudson Light & Power Dept.	(1) [X] An Original (2) [ ] A Resubmission	3/31/85	12/31/84

PART III: BALANCE SHEET — END OF YEAR

Some of the accounts listed below are defined on page ii. Refer to the U.S. of A for those other accounts not defined on page ii.

Line No.	Assets and Other Debits (a)	Amount (b)	Line No.	Liabilities and Other Credits (a)	Amount (b)
1	UTILITY PLANT		33	INVESTMENT OF MUNICIPALITY & SURPLUS	
2	Utility Plant	$5,858,631	34	Investment of Municipality	$52,363
3	(Less) Accumulated Provision for Depreciation & Amortization		35	Constructive Surplus or Deficit	None
4	Net Utility Plant *(Line 2 less line 3)*	5,858,631	36	Retained Earnings	10,094,341
5	INVESTMENTS		37	TOTAL Investment & Surplus *(Enter Total of lines 34 thru 36)*	10,146,704
6	Nonutility Property (Less Accum. Provision for Depreciation and Amortization: $)		38	LONG-TERM DEBT	
			39	Bonds	
7	Advances to Municipality		40	Advances from Municipality	
8	Investments & Special Funds		41	Other Long-Term Debt	
			42	Unamort. Premium on Long-Term Debt	
9	TOTAL Investments *(Enter Total of lines 6 thru 8)*	None	43	Unamortized Discount on Long-Term Debt-Debit	
10	CURRENT AND ACCRUED ASSETS		44	TOTAL Long-Term Debt *(Enter Total of lines 39 thru 43)*	None
11	Cash & Working Funds	1,211,207	45	CURRENT AND ACCRUED LIABILITIES	
12	Temporary Cash Investments	1,344,588			
13	Notes & Accounts Receivable (Less Accum. Provision for Uncollected Accounts: $)	1,518,516	46	Warrants Payable	None
			47	Notes and Accounts Payable	258,591
			48	Payables to Municipality	None
14	Receivables from Municipality	None	49	Customer Deposits	150,003
15	Materials & Supplies	922,709	50	Taxes Accrued	None
16	Prepayments	238,092	51	Interest Accrued	None
17	Misc. Current & Accrued Assets	6,083	52	Misc. Current & Accrued Liabilities	51,241
18	TOTAL Current & Accrued Assets *(Enter Total of lines 11 thru 17)*	5,241,195	53	TOTAL Current & Accrued Liabilities *(Enter Total of lines 46 thru 52)*	459,835
19	DEFERRED DEBITS		54	DEFERRED CREDITS	
20	Unamortized Debt Expense		55	Customer Advances for Construction	23,050
21	Extraordinary Property Losses		56	Other Deferred Credits	256,726
22	Miscellaneous Deferred Debits	36,489	57	Unamortized Gain on Reacquired Debt	None
23	Unamortized Loss on Reacquired Debt		58	TOTAL Deferred Credits *(Enter Total of lines 55 thru 57)*	279,776
24	TOTAL Deferred Debits *(Enter Total of lines 20 thru 23)*	36,489			
25			59	OPERATING RESERVES	
26			60	Property Insurance Reserve	
27			61	Injuries and Damages Reserve	250,000
28			62	Pensions and Benefits Reserve	
29			63	Miscellaneous Operating Reserves	
30					
31			64	TOTAL Operating Reserves *(Enter Total of lines 60 thru 63)*	250,000
32	TOTAL ASSETS & OTHER DEBITS *(Enter Total of lines 4, 9, 18, 24 thru 31)*	11,136,315	65	TOTAL LIAB. & OTHER CREDITS *(Enter Total of lines 37, 44, 53, 58, and 64)*	11,136,315

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light & Power	(1) ☒ An Original (2) ☐ A Resubmission	3/31/85	12/31/84

PART IV: CONDENSED INCOME STATEMENT FOR THE YEAR

Line No.	Item (a)	Amount (b)
1	Electric Utility Operating Income	
2	Operating Revenues	$13,736,017
3	Operation Expenses	11,795,603
4	Maintenance Expenses	578,299
5	Depreciation and Amortization	567,368
6	Taxes and Tax Equivalents	10,256
7	TOTAL Electric Operating Expenses *(Enter Total of lines 3 thru 6)*	12,951,526
8	Net Operating Revenues	784,491
9	Income from Plant Leased to Others	23,355
10	Electric Utility Operating Income	None
11	Other Utility Operating Income (Utility Departments Other than Electric) *(Specify on next line)*	
12		
13	TOTAL Utility Operating Income *(Enter Total of lines 8 thru 12)*	807,846
14	Other Income *(Explain significant amounts in a footnote)* *	152,797
15	Allowance for Funds Used During Construction	None
16	Gross Income *(Enter Total of lines 13 thru 15)*	960,643
17	Income Deductions	
18	Interest on Long-Term Debt	None
19	Other Income Deductions *(See pg. 4) (Explain significant amounts in a footnote)*	2,798
20	TOTAL Income Deductions *(Enter Total of lines 18 and 19)*	2,798
21	Income Before Extraordinary Items *(Enter Total of line 16 less line 20)*	957,845
22	Extraordinary Income *(See definition (f), page ii)*	None
23	Extraordinary Deductions *(See definition (f), page ii)*	None
24	Net Income *(Enter Total of lines 21 plus line 22 less line 23)*	957,845

*Investment of Depreciation Funds

PART V: ELECTRIC SALES DATA FOR THE YEAR

1. Classify Commercial and Industrial sales into Small (or Commercial) and Large (or Industrial) according to the basis of classification regularly used by the respondent. However, if the regularly used classification is based on demand, and if the difference between small demand and large demand is greater than 1000 KW, then classify demand of 1000 KW or less as small and demand greater than 1000 KW as large.

2. Report number of customers as the sum of the number of meters, plus the number of flat rate accounts. However, where separate meter readings are added for billing purposes, count each group of meters so added as one customer. The average number of customers means the total number of customers at the end of 12 consecutive months divided by 12. If the customer count in the residential service classification includes customers counted more than once because of special services such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification.

Line No	Class of Service (a)	Revenues (b)	Kilowatt Hours (c)	Avg. No. of Customers (d)
1	Residential Sales	$ 4,694,342	60,316,590	7611
2	Commercial and Industrial Sales			
3	Small (or Commercial)	739,328	7,211,267	805
4	Large (or Industrial)	7,531,471	108,176,642	163
5	Public Street and Highway Lighting	819,599	11,483,086	95
6	Other Sales to Ultimate Consumers	(87,095)*	533,046	138
7	TOTAL Sales to Ultimate Consumers	13,697,645	187,720,631	8812
8	Sales for Resale	19,933	218,800	1
9	TOTAL Sales of Electric Energy	13,717,578	187,939,431	8813
10	Other Electric Revenues	41,794		
11	TOTAL Electric Operating Revenues	13,759,372		

EIA-412 (6-82) *Negative fuel charge adjustment of ($145,284) included

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson, Light and Power Dept.	(1) X An Original (2) ☐ A Resubmission	3/31/85	12/31/84

PART VIII: SALES OF ELECTRICITY FOR RESALE

1. Report below the information called for concerning sales during year to other electric utilities and cooperatives, and to cities or other public authorities for distribution to ultimate consumers.

2. For each sale, designate statistical classifications in column (b) as follows: FP, for firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(P), for firm power supplementing customer's own generation or other purchases; O, for other power. Include in the O classification sales in which the power delivered cannot be classified under either of the above definitions.

3. For column (e), enter the quantities shown on the bills rendered.

Line No.	Sales Made To (Enter name) (a)	Statistical Classification (b)	Point of Delivery (State, city, etc.) (c)	Amount of Voltage (d)	Number of Kilowatt Hours Sold (e)	Annual Maximum Demand (Specify KW or KVa) (f)	Revenues: Amount (g)	Revenues: Per KWh (In Cents) (h)
1	MMwec		Marlboro	115KVA	218,800	3000	$5,378	9.1105
2			Hudson, MA					
3			Town Line					
4								
5								
6								
7								

PART IX: OPERATION AND MAINTENANCE EXPENSES

Line No.	Item (a)	Operation (b)	Maintenance (c)	Total (d)
	Production Expenses			
1	Steam Power Generation	$	$	$
2	Nuclear Power Generation			
3	Hydraulic Power Generation			
4	Other Power Generation (Specify:) I.C. Diesel	1,523,733	285,078	1,808,811
5	Purchased Power	8,766,653	None	8,766,653
6	Other Production Expenses			
7	TOTAL Production Expenses	10,290,386	285,078	10,575,464
8	Transmission Expenses	312,444	1,016	313,460
9	Distribution Expenses	55,697	251,352	307,048
10	Customer Accounts Expenses	143,189	None	143,189
11	Sales Expenses	22,289	None	22,289
12	Administrative & General Expenses	971,598	40,853	1,012,451
13	TOTAL ELECT. OPERATION & MAINT. EXPENSES	11,795,603	578,299	12,373,901

PART X: PURCHASED POWER

1. Report below the information called for concerning power purchased for resale during the year.

2. For column (d), enter the quantities shown on the bills rendered.

3. Report interchange transactions as net whether the net is a receipt or a delivery by respondent. Indicate such transactions with an asterisk.

Line No.	Purchased From (Enter name) (a)	Point of Receipt (State, city, etc.) (b)	Amount of Voltage (c)	Number of Kilowatt Hours Purchased (d)	Annual Maximum Demand (Specify KW or KVa) (e)	Cost: Amount (f)	Cost: Per KWh (In Cents) (g)
1	NEPCO	Marlboro	115KVA	87,275,470	15,000	$3,544,965	4.06
2	Pilgrim B.E	Hudson, MA	115KVA	13,127	2,500	720,402	54.8
3	Vermont Yankee	Town Line	115KVA	3,709,446	587	130,114	3.51
4	Maine Yankee		115KVA	7,258,087	1,259	193,375	2.66
5	Wyman-Yarmouth-CMP		115KVA	5,151,480	2,102	367,780	7.14
6	NEPCO-Brayton Point		115KVA	6,306,908	3,500	364,901	5.79
7	NEPCO-Salem Harbour		115KVA	5,926,334	3,500	349,617	5.90
8	Point Lepreau		115KVA	38,330,621	4,870	1,879,170	4.90
9	MMWEC		115 KVA	1,561,771	2,813	117,215	7.50
10	Power used at Power Plant and charged to Plant Operation			(412,298)		(17,568)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Dept.	(1) [X] An Original (2) [ ] A Resubmission	3/31/85	12/31/84

PART XI: UTILITY PLANT

Line No.	Item (a)	Balance Beginning of Year (b)	Additions During Year (c)	Retirements During Year (d)	Transfers and Adjustments (e)	Balance End of Year (f)
	Electric Utility Plant					
	Electric Plant in Service					
1	Intangible Plant	$	$	$	$	$
	Production Plant					
2	Steam Production					
3	Nuclear Production	944				944
4	Hydraulic Production					
5	Other Production *(Specify:)*	4,068,525				4,068,525
6	TOTAL Production Plant	4,069,469				4,069,469
7	Transmission Plant	1,544,685				1,544,685
8	Distribution Plant	4,641,695	618,464	13,200		5,246,959
9	General Plant	1,151,767	134,401	3,257		1,282,911
10	TOTAL Electric Plant in Service	11,407,616	752,865	16,457		12,144,024
11	Electric Plant Leased to Others	None				None
12	Construction Work in Progress—Electric	2,040,755				2,323,759
13	Electric Plant Held for Future Use	None				None
14	Electric Plant Acquisition Adjustments *(See definition (e), page ii)*	None				None
15	TOTAL Electric Plant	13,448,371				14,467,783
16	Plant of Other Utility Depts. *(Specify:)*	None				None
17		None				None
18	TOTAL Utility Plant	13,448,371	1,059,068	39,656		14,467,783

PART XII: ACCUMULATED PROVISIONS FOR DEPRECIATION OF UTILITY PLANT

Line No.	Name of Utility Department (a)	Balance Beginning of Year (b)	Depreciation Accruals for Year (c)	Net Charges for Plant Retired During Year (d)	Other Items Debit or Credit *(Explain)* (e)	Balance End of Year (f)
1	Electric	$1,676,762	$ 567,368	$ None	$ 267,441*	$1,474,569
2	Other Utility Department *(Specify:)*				(1,037,002)	
3						
4						
5	TOTAL	1,676,762	567,368	None	(769,561)	1,474,569

*Interest on investment	153,751
Reimbursement for Plant Sold	113,690
Amount expended for construction	1,037,002

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Dept.	(1) [X] An Original (2) [ ] A Resubmission	3/31/85	12/31/84

PART XIV: TAXES, TAX EQUIVALENTS, CONTRIBUTIONS, AND SERVICES DURING YEAR

1. Report below the information called for on contributions and services to the municipality or other government units by the electric utility and, conversely, by those bodies to the electric utility. Do not include: (a) loans and advances which are subject to repayment or which bear interest, (b) payments in retirement of loans or advances previously made, (c) contributions by the municipality of funds or property which are of the nature of investment in the electric utility department.

2. Enter in column (c) the total contributions made or received. Show in column (d) amounts included in column (c) which have been accounted for in the respondent's financial statements, i.e., balance sheet, income account, earned surplus, operating revenues, operating expenses, etc. Show in column (e) amounts which are not accounted for in respondent's financial statements. For those amounts not included in respondent's financial statements, explain in a footnote the reason for their omission.

3. Report below only taxes that are chargeable to operations of the electric utility department. Exclude gasoline and other sales taxes which are included in the cost of transportation and materials.

4. Report as tax equivalents only those amounts which are understood to constitute payments equivalent to or in lieu of amounts which would be paid if the electric utility department were subject to local tax levies.

5. For Other *(Specify)*, use a supplemental page if the lines provided are not sufficient.

Line No.	Item (a)	KWh (1,000's) (b)	Amount of Contribution or Value of Service Total (c)	Included in Financial Statements (d)	Not Included in Financial Statements (e)
	By the Electric Utility to the Municipality or Other Government Units				
1	Taxes		$	$	$
2	Tax Equivalents		200,000	200,000	None
3	To General Funds of the Municipality				
4	Other *(Specify:)*				
5					
6	TOTAL Contributions *(Total of lines 1 thru 6)*		200,000	200,000	None
7	Street and Highway Lighting	1221	78,255	78,255	None
8	Municipal Pumping				
9	Other Municipal Light and Power				
10	Other Electric Service				
11	Nonelectric Service *(Specify:)*				
12					
13	TOTAL Services *(Total of lines 7 thru 12)*	1221	78,255	78,255	None
14	TOTAL Contributions and Services by the Electric Utility *(Total of lines 6 and 13)*	1221	278,255	278,255	None
	By the Municipality or Other Government Units to the Electric Utility				
15	For Operations and Property Maintenance				
16	Other *(Specify:)*				
17					
18	TOTAL Contributions *(Total of lines 15 thru 17)*	None	[illegible]	None	None
19	Office Space				
20	Water				
21	Engineering Service				
22	Legal Service				
23	Other Service *(Specify:)*				
24					
25	TOTAL Services *(Total of lines 19 thru 24)*	None	None	None	None
26	TOTAL Contributions and Services by the Municipality *(Total of lines 18 and 25)*	None	None	None	None
27	Net Contributions and Services by the Electric Utility to the Municipality or Other Government Units *(Total of line 14 less line 26)*	1221	278,255	278,255	None

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	December 31, 19

PART XV: LARGE-ELECTRIC GENERATING PLANTS USING FUEL

1. Large plants are plants of 25,000 KW or more of installed capacity (name plate rating). Include gas-turbine and internal combustion plants of 10,000 KW and more on this page. Include also nuclear plants.
2. If any plant is equipped with combinations of steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas turbine with the steam plant.
3. Indicate with asterisks and footnotes if any plant is leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give that which is available, specifying period in a footnote.
5. If a group of employees attends more than one generating plant, report on line 10 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, give the Btu content of the gas and the quantity of fuel burned, converted to Mcf ft (14.73 psia at 60°F).
7. The figure entered on line 20 (Fuel) should be consistent with the

* Limited to 16,200 by Diesel

Line No.	Item (a)	Plant Name: Cherry St. Station (b)	Plant Name: H.L. & P. Peaking (c)
1	Kind of Plant (Steam, Internal Comb., Gas Turb., or Nuclear)	Internal Comb.	Internal Comb.
2	Year Originally Constructed	1897	1962
3	Year Last Unit Was Installed	1972	1962
4	TOTAL Inst. Capacity (Max. Gen. Name Plate Ratings in KW)	17,150*	4,400
5	Net Peak Demand on Plant (KW for 60 Minutes)	15,200	1,900
6	Plant Hours Connected to Load	8760	8760
7	Net Continuous Plant Capability (KW)		
8	When Not Limited by Condenser Water	15,200	4,400
9	When Limited by Condenser Water	15,200	4,400
10	Average Number of Employees	11	
11	Net Generation, Exclusive of Plant Use	15,094,764	3,643,136
12	Cost of Plant		
13	Land and Land Rights	5,500	None
14	Structures and Improvements	332,640	None
15	Equipment Costs	3,019,275	712,054
16	TOTAL Cost	3,357,415	712,054
17	Cost per KW of Installed Capacity (Line 4)	207	162
18	Production Expenses		
19	Operation Supervision and Engineering	13,588	
20	Fuel	1,312,277	
21	Coolants and Water (Nuclear Plants Only)		
22	Steam Expenses		
23	Steam from Other Sources		
24	Steam Transferred (Cr.)		
25	Electric Expenses		
26	Misc. Steam Power Expenses (or Nuclear)	197,868	
27	Rents		
28	Maintenance Supervision and Engineering	14,460	
29	Maintenance of Structures	5,195	
30	Maintenance of Boiler Plant (or Reactor Plant)		
31	Maintenance of Electric Plant	262,166	
32	Maintenance of Misc. Steam Plant (or Nuclear)	3,257	
33	TOTAL Production Expenses	1,808,811	
34	Expenses per Net KWh (Mills—2 Places)	6.57¢	

Line No.	Item (a)	(b) Coal	(b) Gas	(b) Oil	(c) Coal	(c) Gas	(c) Oil
35	Fuel: (Kind)	Coal	Gas	Oil	Coal	Gas	Oil
36	Unit: (Coal—Tons of 2,000 Lb.) (Oil—Barrels of 42 Gals.) (Gas—Mcf) (Nuclear-Indicate)		MC.FT	42 gal			
37	Quantity (Units) of Fuel Burned		247,723	7646			
38	Average Heat Content of Fuel Burned (Btu per Lb. of Coal, per Gal. of Oil, or per Cu. Ft. of Gas)		910 BTU	140,000 BTU			
39	Average Cost of Fuel per Unit, as Delivered F.O.B. Plant During Year		$4.43	$32.75			
40	Average Cost of Fuel per Unit Burned		$4.43	$28.00			
41	Average Cost of Fuel Burned per Million Btu		$4.87	$ 4.76			
42	Average Cost of Fuel Burned per KWh Net Generation		*.0476				
43	Average Btu per KWh Net Generation		*9,819				

* combined

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XV: LARGE-ELECTRIC GENERATING PLANTS USING FUEL (Continued)

figures entered on line 37 (Quantity of Fuel Burned), line 38 (Avg. Heat Content), line 40 (Avg. Cost of Fuel) and line 41 (Avg. Cost of Fuel Burned).

8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

9. The items under Cost of Plant, line 12, represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

10. For I.C. and G.T. plants, report Operating Expenses (account nos. 548 and 549) on line 25 "Electric Expenses," and Maintenance (account nos. 553 and 554) on line 31 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate with an asterisk automatically operated plants.

11. If the respondent operates a nuclear power generating plant, attach (a) a brief explanation accounting for the cost of power generated, including any attribution of excess costs to research and development expenses; (b) a brief explanation of the fuel accounting, specifying the accounting methods and types of cost units under with respect to the various components of the fuel cost; and (c) additional information as may be informative concerning the type of plant, kind of fuel used, and other physical and operating characteristics of the plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Item (a)	Line No.
									Kind of Plant	1
									Year Constructed	2
									Year Last Unit	3
									TOTAL Installed Capacity	4
									Net Peak Demand	5
									Plant Hours	6
									Net Capability	7
									Not Limited	8
									Limited	9
									Employees	10
									Net Generation	11
									Cost of Plant	12
									Land	13
									Structures	14
									Equipment	15
									TOTAL	16
									Cost per KW	17
									Production Expenses	18
									Operation Supervision	19
									Fuel	20
									Coolants	21
									Steam Expenses	22
									Steam Other Sources	23
									Steam Transferred	24
									Electric Expenses	25
									Misc. Expenses	26
									Rents	27
									Maintenance Supervision	28
									Maint. of Structures	29
									Maint. of Boiler	30
									Maint. of Electric Plant	31
									Maint. of Misc. Steam	32
									TOTAL Production	33
									Expenses	34
Coal	Gas	Oil	Coal	Gas	Oil	Coal	Gas	Oil	Fuel: (Kind)	35
									Unit	36
									Quantity	37
									Avg. Heat Content	38
									Avg. Cost F.O.B.	39
									Avg. Cost Burned	40
									Avg. Cost Btu	41
									Avg. Cost KWh	42
									Avg. Btu per KWh	43

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XVI: HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 KW or more of installed capacity (name plate ratings).

2. Indicate by an asterisk and explain in a footnote if any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility. If a licensed project, give project number.

3. For line 5, if net peak demand for 60 minutes is not available, give that which is available, specifying period.

4. For line 10, if a group of employees attends more than one generating plant, report the approximate average number of employees assignable to each plant.

Line No.	FPC Licensed Project No. and Plant Name:	FPC Licensed Project No. and Plant Name	FPC Licensed Project No. and Plant Name
1	Kind of Plant (Run-of-River or Storage)		
2	Year Originally Constructed		
3	Year Last Unit was Installed		
4	TOTAL Installed Capacity (Generator Name Plate Ratings in KW)		
5	Net Peak Demand on Plant (Kilowatts for 60 Minutes)		
6	Plant Hours Connected to Load		
7	Net Plant Capability (Kilowatts)		
8	Under the Most Favorable Operating Conditions		
9	Under the Most Adverse Operating Conditions		
10	Average Number of Employees	NOT APPLICABLE	
11	Net Generation, Exclusive of Plant Use		
12	Cost of Plant		
13	Land and Land Rights		
14	Structures and Improvements		
15	Reservoirs, Dams, and Waterways		
16	Equipment Costs		
17	Roads, Railroads, and Bridges		
18	TOTAL Cost *(Enter Total of lines 14 thru 17)*		
19	Cost per KW of Installed Capacity *(Line 18 ÷ line 4)*		
20	Production Expenses		
21	Operation Supervision and Engineering		
22	Water for Power		
23	Hydraulic Expenses		
24	Electric Expenses		
25	Misc. Hydraulic Power Generation Expenses		
26	Rents		
27	Maintenance Supervision and Engineering		
28	Maintenance of Structures		
29	Maintenance of Reservoirs, Dams, and Waterways		
30	Maintenance of Electric Plant		
31	Maintenance of Misc. Hydraulic Plant		
32	TOTAL Production Expenses *(Total of lines 21 thru 31)*		
33	Expenses per Net KWh (Mills—2 Places)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	DEc. 31, 1984

PART XVI: HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts Under Production Expenses, do not include Purchased Power, System Control, and Load Dispatching, or Other Expenses classified as "Other Power Supply Expenses."

6. If any plant is equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment, report each as a separate plant.

FPC Licensed Project No. and Plant Name	FPC Licensed Project No. and Plant Name	FPC Licensed Project No. and Plant Name	FPC Licensed Project No. and Plant Name	Line No.
			Kind of Plant	1
			Year Constructed	2
			Year Last Unit	3
			TOTAL Installed Capacity	4
			Net Peak Demand	5
			Plant Hours	6
			Net Capability	7
			Most Favorable	8
			Most Adverse	9
	NOT APPLICABLE		Employees	10
			Net Generation	11
			Cost of Plant	12
			Land	13
			Structures	14
			Reservoirs, Etc.	15
			Equipment	16
			Roads, Etc.	17
			TOTAL	18
			Cost per KW	19
			Production Expenses	20
			Operation Supervision	21
			Water for Power	22
			Hydraulic Expenses	23
			Electric Expenses	24
			Misc. Expenses	25
			Rents	26
			Maintenance Supervision	27
			Maintenance Structures	28
			Maint. Reservoirs, Etc.	29
			Maint. Electric Plant	30
			Maint. Hydraulic Plant	31
			TOTAL	32
			Expenses per Net KWh	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Dept.	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	December 31, 1984

PART XVIII: GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants include: all plants of less than 25,000 KW. Include the reporting of unconventional plants on this page.
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give particulars (details) in a footnote. If the project is licensed, give project number in a footnote.
3. List under appropriate subheadings steam, hydro, nuclear, internal combustion, and gas-turbine plants. If the respondent operates a nuclear power generating plant attach (a) a brief explanatory statement concerning accounting for the cost of power generated, including any attribution of excess costs to research and development expenses; (b) a brief explanation of types of cost units used with respect to the various components of the fuel cost; and (c) such additional information as may be informative concerning the type of plant, kind of fuel used, fuel enrichment, by type and quantity for the reporting period, and other physical and operating characteristics of the plant.
4. For column (d) if net peak demand for 60 minutes is not available, give data that is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report such as one plant.

Line No.	Name of Plant (a)	Year Orig. Const (b)	Installed Capacity-Name Plate Rating-KW (c)	Net Peak Demand KW (60 Min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost Per KW Inst. Capacity (g)	Production Expenses: Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Cost Cents Per Million Btu (l)
1												
2												
3												
4												
5												
6					NOT APPLICABLE							
7												
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EIA-412 (6-82)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [x] An Original (2) [ ] A Resubmission	Masrch 31, 1985	Dec. 31, 1984

PART XIX: STEAM-ELECTRIC GENERATING PLANTS

1. Include in this part steam-electric plants of 25,000 KW (name plate rating) or more of installed capacity.

2. Report the information called for concerning generating plants and equipment at end of year. Show unit type installation, boiler and turbine-generator, on same line.

3. Exclude from this part the book cost of that plant which is included in Account 121 (Nonutility Property).

4. Designate with an asterisk any generating plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish on a supplemental page a brief statement ex-

Line No.	Name of Plant (a)	Location of Plant (b)	BOILERS: Number and Year Installed (c)	BOILERS: Kind of Fuel and Method of Firing (d)	BOILERS: Rated Pressure (psig) (e)	BOILERS: Rated Steam Temperature (Enter 1050/1000 for reheat boilers) (f)	BOILERS: Rated Max. Continuous M lbs. Steam Per Hour (g)
1							
2							
3							
4							
5							
6		NOT APPLICABLE					
7							
8							
9							
10							
11							
12							
13							
14							
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31							
32							
33							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) X An Original (2) ☐ A Resubmission	March 31, 1985	Dec. 31. 1984

PART XIX: STEAM-ELECTRIC GENERATING PLANTS (Continued)

plaining the arrangement and giving particulars (details) on such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses or revenues, and how expenses and/or revenues are accounted for, and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Report any generating plant or portion thereof leased to another utility. Give name of lessee, date and term of lease, and annual rent and how determined. Specify whether lessee is an associated utility.

6. Report any plant or equipment owned by the utility but not operated or leased to another utility. If such plant or equipment was not operated within the past year, state if it has been retired in the books of account or what disposition is contemplated for the plant or equipment and its book cost.

7. Include in this part gas-turbines operated in a combined cycle with a conventional steam unit and its associated steam unit.

8. In columns (e) thru (g), (i), (k), and for dual-rated installations, report ratings of both the boiler and the turbine-generator.

TURBINE GENERATORS

(For cross-compound turbine-generators, report H.P. section on one line and L.P. section on the next line. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps in terms of full load requirements.)

Year Installed	TURBINES *(In column (j), indicate whether tandem compound (TC), cross compound (CC), single casing (SC), topping unit (T), or noncondensing (NC). Show back pressure.)* Max Rating (In KW)	Type	Steam Pressure at Throttle (psig)	R.P.M.	GENERATORS Name Plate Rating (In kilowatts) At Minimum Hydrogen Pressure	At Maximum Hydrogen Pressure	Hydrogen Pressure *(Designate air cooled generators)* Min.	Max.	Power Factor	Voltage (In KV) *(Specify characteristics if other than 3 phase, 60 cycle)*	Plant Capacity, Maximum Generator Name Plate Rating (Should agree with column (n))	Optional: Name of Plant	Line No.
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(a)	
													1
													2
													3
													4
													5
													6
						NOT APPLICABLE							7
													8
													9
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													33

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XX: HYDROELECTRIC GENERATING PLANTS

1. Include in this part hydro plants of 10,000 KW (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this part the book cost of the plant which is included in Account 121 (Nonutility Property).

4. Designate any plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish on a supplementary page a brief statement explaining the arrangement

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	WATER WHEELS: Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head With Pond Full (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10		NOT APPLICABLE					
11							
12							
13							
14							
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22							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XX: HYDROELECTRIC GENERATING PLANTS (Continued)

and giving particulars (details) on such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease, and annual rent and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned but not operated or leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost is contemplated.

7. In column (e), indicate whether water wheel is horizontal or vertical type. Also indicate type of runner-Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), or Impulse (I). Designate reversible type units in a footnote.

WATER WHEELS (Continued)			GENERATORS							Optional	
Design Head (h)	R.P.M. (i)	Maximum HP Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Frequency or d.c. (n)	Name Plate Rating of Unit (In kilowatts) (o)	Number of Units in Plants (p)	Total Installed Generating Capacity (Name Plate Ratings) (In kilowatts) (q)	Name of Plant (a)	Line No.
											1
											2
											3
											4
											5
											6
											7
											8
											9
				NOT APPLICABLE							10
											11
											12
											13
											14
											15
											16
											17
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) X An Original (2) A Resubmission	March 31, 1985	Dec. 31. 1984

PART XXI: INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS

1. Include in this part internal-combustion engine and gas-turbine plants of 10,000 kilowatts and more.

2. Report the information called for concerning plants and equipment at end of year. Show associated prime movers and generators on the same line.

3. Exclude from this part the book cost of the plant which is included in Account 121 (Nonutility Property).

4. Designate any plants or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant other than a leased plant, or portion thereof, for which the respondent is not the sole owner, but which the respondent operates or shares in the operation of, furnish a suc-

Line No.	Name of Plant (a)	Location of Plant (b)	PRIME MOVERS: Internal-Combustion or Gas-Turbine (c)	Year Installed (d)	Cycle (e)	Belted or Direct Connected (f)
1	Cherry St.	Cherry St., Hudson MA	Intermal Comb	1937	2	Direct
2	Cherry St.	Cherry St., Hudson MA	Internal Comb	1951	2	Direct
3	Cherry St.	Cherry St., Hudson Ma	Internal Comb	1955	2	Direct
4	Cherry St.	Cherry St., Hudson MA	INternal Comb	1960	2	Direct
5	Cherry St.	Cherry St., Hudson MA	Internal Comb	1972	4	Direct
6						
7						
8						
9						
10	Hudson Light					
11	Peaking Plt.	Cherry St., Hudson MA	Internal Comb.	1962	2	Direct
12	Hudson Light					
13	Peaking Plt.	Cherry St., Hudson MA	Internal Comb	1962	2	Direct
14						
15						
16						
17						
18						
19						
20						
21						
22						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XXI: INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS (Continued)

cinct statement explaining the arrangement and giving particulars (details) on such matters as percent of ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate in a footnote any plant or portion thereof leased to another company and give name of lessee, date and term of lease, and annual rent and how determined. Specify whether lessee is an associated company.

6. Designate in a footnote any plant or equipment owned but not operated or leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost is contemplated.

7. In column (e), for gas-turbine prime movers, indicate whether basic cycle is open or closed; for internal-combustion, indicate whether cycle is 2 or 4.

PRIME MOVERS (Continued)	GENERATORS							Optional	
Rated HP of Unit (g)	Year Installed (h)	Voltage (i)	Phase (j)	Frequency or d.c. (k)	Name Plate Rating of Unit (In kilowatts) (l)	Number of Units in Plant (m)	Total Installed Generating Capacity (Name Plate Rating) (In kilowatts) (n)	Name of Plant (a)	Line No.
1480	1937	2300	3Ø	60 cyl.	1000	1	1000		1
4250	1951	4160	3Ø	60 cyl.	3300	1	3000		2
5100	1955	4160	3Ø	60 cyl.	4000	1	3600		3
4250	1943	4160	3Ø	60 cyl.	3250	1	3000		4
7760	1972	4160	3Ø	60 cyl.	5600	1	5600		5
									6
									7
									8
									9
									10
3168	1962	4160	3Ø	60 cyl.	2200	1	2200		11
									12
3168	1962	4160	3Ø	60 cyl.	2200	1	2200		13
									14
									15
									16
									17
									18
									19
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									40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XXIII: TRANSMISSION LINE STATISTICS

1. Report below information requested concerning each transmission line. Show highest voltages first. If more space is required, use supplemental page using the column headings shown on this page.
2. Indicate in column (d) whether the type of supporting structure is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction.
3. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another, give name of lessor.
4. Designate in a footnote any transmission line leased to another and give name of lessee.
5. For column (c), if the voltage used is different from operating, report the difference in a footnote.

Line No.	Designation (Name of Terminal Station) From (a)	Designation (Name of Terminal Station) To (b)	Operating Voltage (c)	Type of Supporting Structure (d)	LENGTH (Pole Miles) On Structures of Line Designated (e)	LENGTH (Pole Miles) On Structures of Another Line (f)	Size of Conductor and Material (h)	Number of Circuits (g)
1	Marlboro-	Forest Avenue						
2	Hudson, MA.	Sub-station	115KV	Steel	3.2		336.4	2
3	Town line at	Hudson, MA.		Poles			MCM	
4	River Street						ACSR	
5							"Linnet"	
6								
7								
8								
9								
10								
11								
12								
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XXV: ELECTRIC ENERGY ACCOUNT

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

2. Submit an explanatory statement of any interchange, transmission, or wheeling transaction, giving name of other party and amount of compensation for the service to or by the respondent.

Line No.	Item (a)			Kilowatt-Hours (b)
	SOURCES OF ENERGY			
	Generation (Excluding Station Use)			
1	Steam			
2	Nuclear			
3	Hydro			
4	Diesel			
5	Gas Turbine			27,536,160
6	Other (Specify:)			
7				
8	TOTAL Generation (Enter Total of lines 1 thru 7)			27,536,160
9	Purchases			155,120,946
10	Interchanges	In (Gross)	28,170,838 KWh	
11		Out (Gross)	6,194,610 KWh	
12		Net (Enter Total of lines 10 and 11)		21,976,228
13	Transmission for/by Others (Wheeling)	Received	KWh	
14		Delivered	KWh	
15		Net (Enter Total of lines 13 and 14)		NONE
16	TOTAL (Enter Total of lines 8, 9, 12 and 15)			204,633,334
	DISPOSITION OF ENERGY			
17	Sales to Ultimate Consumers (Including Interdepartmental Sales)			187,720,631
18	Sales for Resale			218,800
19	Energy Furnished Without Charge			none
	Energy Used by the Utility (Excluding Station Use)			
20	Electric Department Only (Use by Other Departments Should be Accounted for as Sales)			298,087
21	Energy Losses: Transmission and Conversion Losses			7,472,134
22	Distribution Losses			5,441,682
23	Unaccounted for Losses			3,482,000
24	TOTAL Energy Losses (Enter Total of lines 21 thru 23)			16,395,816
25	(Percent Lost of Total Energy Generated, Purchased, and Interchanged)			8.012%
26	TOTAL (Enter Total of lines 17 thru 19, 20, and 24)			204,633,334

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Report Year Ending (Mo, Da, Yr)
Town of Hudson Light and Power Department	(1) [X] An Original (2) [ ] A Resubmission	March 31, 1985	Dec. 31, 1984

PART XXVI: FOOTNOTE DATA

Page Number (a)	Part Number (b)	Line Number (c)	Column Number (d)	Comments (e)
				NONE

ANNUAL REPORT
1984

CL&P
THE CONNECTICUT LIGHT AND POWER COMPANY
a subsidiary of Northeast Utilities

8504180451

DIRECTORS

PHILIP T. ASHTON
Senior Vice President

JOHN P. CAGNETTA
Vice President

WILLIAM B. ELLIS
Chairman and Chief Executive Officer

WALTER F. FEE
Executive Vice President

E. JAMES FERLAND
President and Chief Operating Officer

BERNARD M. FOX
Senior Vice President and Chief Financial Officer

FRANK R. LOCKE
Vice President and Chief Administrative Officer,
Western Massachusetts Electric Company

LEON E. MAGLATHLIN, JR.
Senior Vice President

LAWRENCE H. SHAY
Senior Vice President

WALTER F. TORRANCE, JR.
Senior Vice President, General Counsel and
Assistant Secretary

OFFICERS

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Chairman and Chief Executive Officer

E. JAMES FERLAND
President and Chief Operating Officer

WALTER F. FEE
Executive Vice President

PHILIP T. ASHTON
Senior Vice President

WILLIAM G. COUNSIL
Senior Vice President

BERNARD M. FOX
Senior Vice President and
Chief Financial Officer

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Senior Vice President

LAWRENCE H. SHAY
Senior Vice President

WALTER F. TORRANCE, JR.
Senior Vice President, General
Counsel and Assistant Secretary

WARREN F. BRECHT
Vice President

C. THAYER BROWNE
Vice President

CARROLL A. CAFFREY
Vice President

JOHN P. CAGNETTA
Vice President

TOD O. DIXON
Vice President

RAYMOND E. DONOVAN
Vice President

ALBERT J. HAJEK
Vice President

WARREN A. HUNT
Vice President

FRANCIS L. KINNEY
Vice President

HARRIE R. NIMS
Vice President

LEONARD A. O'CONNOR
Vice President and Treasurer

JOHN F. OPEKA
Vice President

RICHARD A. RECKERT
Vice President

WALTER T. SCHULTHEIS
Vice President

C. FREDERICK SEARS
Vice President

JOHN J. SMITH
Vice President

RICHARD P. WERNER
Vice President

CHARLES S. BEACH
Regional Vice President—Western

W. LINDSEY BOOTH
Regional Vice President—Eastern

THOMAS F. BRENNAN
Regional Vice President—Central

LESLEY C. GEROULD
Regional Vice President—Southern

ALBERT E. MAGEE
Regional Vice President—Northern

GEORGE D. UHL
Controller

ROBERT W. BISHOP
Secretary

CHERYL W. GRISE
Assistant Secretary

DOUGLAS R. TEECE
Assistant Secretary

ROBERT C. ARONSON
Assistant Treasurer

DAVID H. BOGUSLAWSI
Assistant Treasurer

FEBRUARY 28, 1985

The Connecticut Light and Power Company

February 28, 1985

To Our Preferred Stockholders:

The financial statements and statistical data contained in this report reflect the results of operations of The Connecticut Light and Power Company (CL&P) for 1984. The 1984 annual report of Northeast Utilities, which provides information regarding the entire Northeast Utilities' system, including CL&P, has also been mailed to all CL&P preferred stockholders. This report is brief for that reason.

Because of the steady improvement in its financial condition in 1984, CL&P did not file any rate cases in 1984. Higher sales levels, a retail rate increase granted in December 1983 and cost containment measures undertaken by CL&P were all responsible for the increase in net income in 1984. CL&P expects to file rate applications in both its retail and wholesale jurisdictions in 1985.

Millstone 3 is now closer to completion due to efforts made in 1984. The total estimated cost of the Company's 52.6115 percent ownership in the unit is currently estimated to be $2.01 billion, based on the unit's projected cost of $3.825 billion. The unit was estimated to be 93 percent complete at December 31, 1984.

In 1984, CL&P bonds were upgraded by Standard & Poor's from BBB- to BBB+ and its preferred stock was upgraded from BB to BBB.

In 1984, CL&P issued $75 million principal amount of first mortgage bonds, and $80.8 million of variable rate pollution control notes and entered into a $75 million interest rate exchange agreement. During 1985, CL&P plans to issue additional preferred stock and long-term debt.

Sincerely,

President

Chairman

The Connecticut Light and Power Company

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

This section contains management's assessment of the The Connecticut Light and Power Company's (the Company) financial condition and the principal factors which have an impact on the results of operations. This discussion should be read in conjunction with the Company's financial statements and footnotes.

FINANCIAL CONDITION

The Company showed steady improvement in its financial condition throughout 1984. The Company's net income increased to $284.2 million in 1984 from $227.2 million in 1983. The increase in earnings is attributable to a combination of the effects of a higher level of sales from an improved economy and rate increases, as well as cost containment measures taken by the Company. Notwithstanding these improvements, the allowance for funds used during construction (AFUDC), a noncash item representing the estimated cost of capital funds used to finance the Company's construction program, continues to provide a substantial portion of the Company's earnings. Continued progress will be necessary for the Company to fully regain and maintain financial health. Considerable uncertainties, such as the timely completion and rate recognition of the Millstone 3 nuclear unit, still face the Company.

Legislation enacted in Connecticut during 1983 could limit the recoverability, with certain exceptions, of Millstone 3 construction costs above the unit's 1982 estimated cost of $3.54 billion. In August 1984, Northeast Utilities (NU) announced that the estimated cost of Millstone 3 was expected to exceed the 1982 estimate of $3.54 billion. NU is now using a projected cost for the unit of $3.825 billion. The Company has a 52.6115 percent ownership interest in this unit. The Company is not able at this time to determine how much, if any, of the total cost of Millstone 3, above $3.54 billion would not be recoverable because of this law. The Company believes that it is constitutionally entitled to full recognition of its prudently incurred investment in plants necessary to provide service to its customers. If necessary, management intends to pursue appropriate measures, which could include seeking legislative change or administrative and court appeals, to obtain full rate recognition of its prudent investment in Millstone 3.

Because the rate levels necessary to support full recognition of its prudent Millstone 3 investment will be substantially higher than current rates, the Company expects that the Connecticut Department of Public Utility Control (DPUC) will consider requiring that the costs associated with Millstone 3 be phased into rates over a limited number of years after the unit enters service. Management believes that a reasonable phase-in plan over a relatively short period of time could be manageable from a financial point of view. However, failure to provide full rate recognition for Millstone 3 upon its completion would represent a break from traditional rate-making principles and could be interpreted by investors as symptomatic of an unsupportive regulatory environment. This perception could result in increased cost and/or decreased availability of funds for the Company's future capital needs, and could have long-term, negative effects on future electric rates.

The Company has a 4.1 percent ownership interest in the Seabrook project. In 1984, legislation was enacted in Connecticut requiring the DPUC to establish a limit on the amount of construction costs of Seabrook unit 1 that may be made part of the rate base or otherwise included in the rates of the Company. The DPUC established such a limit, with certain exceptions, at $4.7 billion, of which approximately $191 million would be applicable in the determination of the Company's rates. This legislation also required the DPUC to determine the economic viability of Seabrook unit 1, the ability of the owners to finance the project to completion, and the probability that the project would be completed and placed in service. In its decision, the DPUC concluded that Seabrook unit 1 was both economically and financially viable. The Company continues to believe that the timely completion of Seabrook unit 1 is in the public interest, in the best interests of ratepayers and investors, and economically more desirable than cancellation, but completion of the unit is not assured.

Construction Program

The Company's 1984 construction expenditures of $508.3 million were the highest in its history. Projected construction expenditures, including AFUDC but excluding nuclear fuel, for 1985 through 1989 are presented in the following table. Annual construction expenditures are projected to peak in 1985 and decline to a lower level after Millstone 3 begins commercial operation in 1986.

	Electric Generating Facilities	Other	Total
	(Thousands of Dollars)		
1985	$486,837	$92,181	$579,018
1986	212,810	92,496	305,306
1987	110,254	89,024	199,278
1988	62,666	89,363	152,029
1989	51,945	94,792	146,737

The construction of Millstone 3 is the most significant item in the construction program, representing about 72 percent of the program in 1984 and 56 percent of the 1985 and 1986 programs. Millstone 3 remains on schedule for its planned in-service date of May 1986. The total estimated cost of the Company's 52.6115 percent ownership interest in the unit (representing 605 MW), based on the analysis completed in 1984, is currently estimated to be $2.01 billion of the unit's projected cost of $3.825 billion. The construction of the unit was estimated to be 93 percent complete at December 31, 1984.

The construction program also includes the Company's 4.1 percent interest in Seabrook unit 1. The Company considers Seabrook unit 2 to be effectively canceled and, therefore, no costs for further construction of Seabrook unit 2 are included in the construction program, although there are some minimal expenditures included for security and other measures necessary to preserve and protect any assets represented by the unit. For financial planning purposes, the Company is projecting that Seabrook unit 1 will be placed in service in the third quarter of 1987 and the Company's share of the cost will be approximately $210 million. The Company's share of the construction expenditures for Seabrook unit 1 is estimated to be $77 million for 1985 through 1987.

In addition to construction expenditures, the Company estimates that nuclear fuel requirements will be $254 million for the years 1985 through 1989.

Financing

It is essential that the Company regain and maintain its financial health to assure access at reasonable cost to financial markets so as to acquire the funds needed for its ongoing construction program. Cash requirements in excess of internally generated funds are financed through short-, intermediate- and long-term borrowings, the issuance of tax-exempt pollution control notes, construction and nuclear fuel trust financings, leasing agreements, sales of preferred stock and capital contributions from the parent company. In addition to construction and nuclear fuel requirements, the Company is obligated to meet debt maturities and cash sinking-fund requirements totaling $231.3 million for the years 1985 through 1989.

Although the level of internal cash generation has increased in recent years, external financing continues to supply a substantial portion of total cash requirements and is expected to continue to do so until Millstone 3 is placed in service and reflected in rates. In 1985, the Company intends to issue additional long-term debt and preferred stock and to utilize construction and nuclear fuel trust arrangements and revolving credit/term loan agreements. In addition, the Company expects to receive open account advances or capital contributions from the parent company.

During 1984, the Company issued approximately $230.8 million of first mortgage bonds, pollution control notes and long-term notes. The Company also received capital contributions of $30 million from the parent company. In addition, the Company and Western Massachusetts Electric Company (WMECO) used the construction trust arrangement to finance a portion of Millstone 3 construction expenditures during 1984. The Company and WMECO continued to utilize a nuclear fuel trust to finance nuclear fuel requirements for Millstone 1 and 2 and their ownership share of Millstone 3. As of December 31, 1984, the Company's portion of the trust's investment in nuclear fuel was $279.9 million.

Some of the Seabrook joint owners experienced financial difficulties in 1984. As a result, to better assure their ability to complete the project, each Seabrook joint owner was required to establish a financing plan and/or agreement to cover its portion of the cost to complete Seabrook unit 1. In September 1984, the Company obtained commitments for letters of credit to assure it will meet its 4.1 percent share of the cash requirements to complete Seabrook unit 1.

The Company and WMECO have done considerable contingency planning to help assure that adequate cash resources will be available to complete Millstone 3. That planning recognized that many of the Seabrook joint owners are also joint owners of Millstone 3. If any of those joint owners do not meet their financial obligations for the continued construction of Millstone 3, the Company and WMECO might find it necessary to take on additional obligations to complete the unit. As a result of such contingency planning, and in addition to the $400 million available credit for the Company and WMECO under the construction trust, the Company and WMECO expanded their credit lines to $398 million. The Company and WMECO have had a $200 million aggregate revolving credit/term loan agreement for several years under which the maximum borrowing limits for the Company and WMECO are $200 million and $60 million, respectively. In late 1984, a new $150 million revolving joint credit facility was added under which the maximum borrowing limits for the Company and WMECO are $150 million and $45 million, respectively. There were no borrowings under either of these agreements during 1984. The Company, along with other system companies, also has $48 million of joint credit line agreements with various regional banks, of which $46 million was available as of December 31, 1984.

Rate Matters

Sufficient rate levels granted on a timely basis in both its regulatory jurisdictions are key factors to enable the Company to achieve satisfactory operating results, increase its internal cash generation and assure the ability to enter the capital markets at a reasonable cost. Therefore, the Company will continue to evaluate the need to file rate applications in its retail and wholesale jurisdictions. Improved earnings made possible by past rate relief, an unexpectedly high level of sales and effective cost containment measures made it unnecessary for the Company to seek higher rates during 1984. The DPUC has scheduled hearings for March 1985 to reconsider rate levels because the Company is currently earning an equity return above that allowed in its December 1983 retail rate case decision. No date for completion of the DPUC reconsideration has been established.

In 1985, the Company expects to file rate applications in both its regulatory jurisdictions to reflect anticipated increases in the cost of providing service and the inclusion of Millstone 3 costs in the Company's rates when the unit enters service, as scheduled, in May 1986, although the timing and the amounts of such filings have not been determined.

RESULTS OF OPERATIONS

Operating Revenues

Operating revenues increased $181.6 million from 1983 to 1984 and $95.0 million from 1982 to 1983. The components of the change in operating revenues for the past two years are as follows:

Changes in Operating Revenues

	Increase/(Decrease) 1984 vs. 1983	1983 vs. 1982
	(Millions of Dollars)	
Rate increases	$ 73.8	$ 95.8
Fuel cost recoveries	50.9	(43.9)
Sales increases and other	56.9	43.1
Total revenue increase	$181.6	$ 95.0

In 1984, electric sales increased 5.2 percent and gas sales increased 7.3 percent. These increases resulted primarily from improved economic conditions in the Company's service area. A 4.3 percent increase in electric sales during 1983 was primarily attributable to warmer than normal summer weather and the improved economic conditions. Gas sales decreased 4.3 percent in 1983 compared to 1982 primarily as a result of lower heating requirements in 1983 and some industrial customers switching from gas to oil. The increase in fuel cost recoveries during 1984 is primarily attributable to the combination of the recovery of electric energy costs on a higher level of sales and the recovery of deferred energy costs from prior years. This increase was offset partially by lower gas fuel cost recoveries as a result of lower prices in 1984. The change in fuel cost recoveries during 1983 reflects the timing of when energy costs were recovered through rates and the effect of lower gas sales.

Electric and Gas Energy Expenses

Electric energy expenses, which include fuel and net purchased and interchange power, increased $70.8 million in 1984 compared to 1983 primarily because of higher kilowatt-hour (kWh) requirements and energy prices in 1984. Electric energy expenses decreased $49.5 million in 1983 compared to 1982 as a result of the matching of revenues and expenses under the provisions of the respective energy adjustment clauses. This decrease was partially offset by increased kWh requirements in 1983.

Gas energy expenses decreased $18.0 million in 1984 compared to 1983 as a result of lower prices in 1984, offset partially by the effect of higher requirements in 1984. Gas energy expenses decreased $6.8 million in 1983 compared to 1982. This decrease can be attributed to lower requirements in 1983 which were offset partially by the effect of slightly higher gas prices.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $24.0 million in 1984 compared to 1983. Although inflation is at a lower rate than in previous years, it still continues to increase the costs for labor, materials and services. This increase was offset partially in 1984 by the effect of lower nuclear refueling and maintenance costs.

Other operation and maintenance expenses increased $52.1 million in 1983 compared to 1982 primarily because of higher nuclear refueling and maintenance costs and the impact of inflation on most expenses. The Company also experienced higher capacity costs from Connecticut Yankee Atomic Power Company and lower sales of capacity to other electric utilities.

Taxes

Federal and state income taxes increased $47.6 million in 1984 compared to 1983 and $39.9 million in 1983 compared to 1982. These increases are attributable to an increase in income in both years and, in 1983, the effect of an increase in the Connecticut Corporation Business Tax rate. In addition, taxes other than income taxes increased $9.2 million in 1984 compared to 1983 and $8.9 million in 1983 compared to 1982. These increases are primarily the result of the Connecticut Gross Receipts Tax on a higher level of revenues.

Interest Charges

Interest charges increased $20.1 million in 1984 compared to 1983 primarily because of higher borrowing levels in 1984, reflecting the need for additional capital to finance the Company's share of Millstone 3 construction costs.

Interest charges decreased $0.7 million in 1983 compared to 1982 primarily as a result of lower short-term borrowings and lower interest rates during 1983. The decrease in short-term borrowings was a result of the issuance of new intermediate- and long-term debt and equity securities during 1983.

Allowance for Funds Used During Construction

The increase in AFUDC of $25.2 million in 1984 and $28.1 million in 1983 was caused by higher average construction work in progress (CWIP) balances attributable primarily to the Millstone 3 construction project. The increase in AFUDC during 1984 was reduced partially by the effect of including about $90 million of the Company's CWIP in rate base.

Impact of Inflation

See Note 10, "Impact of Changing Prices," of Notes to Financial Statements for a discussion on the impact of inflation on the Company.

The Connecticut Light and Power Company

STATEMENTS OF INCOME

For the Years Ended December 31,	1984	1983	1982
	(Thousands of Dollars)		
Operating Revenues	$1,779,238	$1,597,624	$1,502,645
Operating Expenses:			
Operation-			
Fuel	479,861	296,909	403,631
Purchased and interchange power, net.	(23,193)	88,962	31,779
Gas purchased for resale	122,859	140,882	147,637
Other	377,620	346,567	316,929
Maintenance	105,292	112,377	89,936
Depreciation	99,511	95,579	88,145
Federal and state income taxes (Note 4)	182,885	135,648	95,241
Taxes other than income taxes	142,825	133,605	124,688
Total operating expenses	1,487,660	1,350,529	1,297,986
Operating Income	291,578	247,095	204,659
Other Income:			
Allowance for equity funds used during construction	87,383	67,958	41,694
Equity in earnings of regional nuclear generating companies	8,689	8,108	6,734
Other, net	(2,710)	(3,229)	(1,908)
Income taxes applicable to other income-credit	40,230	33,938	30,989
Net other income	133,592	106,775	77,509
Income before interest charges	425,170	353,870	282,168
Interest Charges:			
Interest on long-term debt	172,185	151,893	135,821
Other interest	4,176	4,365	21,125
Allowance for borrowed funds used during construction, net of income taxes	(35,418)	(29,595)	(27,738)
Total interest charges	140,943	126,663	129,208
Net Income	$ 284,227	$ 227,207	$ 152,960

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

The Connecticut Light and Power Company
STATEMENTS OF SOURCES OF FUNDS FOR GROSS PROPERTY ADDITIONS

For the Years Ended December 31,	1984	1983	1982
	(Thousands of Dollars)		
Funds Generated From Operations:			
Net income	$284,227	$227,207	$152,960
Principal noncash items:			
Depreciation	99,511	95,579	88,145
Prior period spent fuel disposal costs	6,438	10,063	1,592
Deferred income taxes, net	93,427	103,384	43,742
Other amortization and noncash items	10,707	5,659	7,646
Amortization of energy adjustment clauses	3,322	(7,779)	59,032
Allowance for equity funds used during construction	(87,383)	(67,958)	(41,694)
Total funds from operations	410,249	366,155	311,423
Less-Cash dividends paid on:			
Common stock	118,440	111,351	79,624
Preferred stock	35,592	30,578	26,287
Net funds generated from operations	256,217	224,226	205,512
Funds Obtained From Financing:			
Long-term debt	230,800	95,000	160,000
Preferred stock	-	50,000	40,000
Increase (decrease) in construction trust	(72,830)	26,689	96,006
Decrease in short-term debt	(5,000)	(11,575)	(151,910)
Increase in obligations under capital leases	84,688	62,646	219,886
Capital contributions from Northeast Utilities (parent company)	30,000	80,000	110,000
Total	267,658	302,760	473,982
Less-Reacquisitions and retirements of long-term debt and preferred stock	19,188	9,906	151,383
Net funds from financing	248,470	292,854	322,599
Other Sources (Uses) of Funds:			
Changes in components of working capital:			
Cash and special deposits	(13,034)	(2,226)	7,471
Receivables and accrued utility revenues	(40,138)	(9,573)	(7,898)
Fuel, materials and supplies	(2,792)	10,896	(1,983)
Accounts payable	(15,161)	13,659	(20,921)
Accrued taxes	42,523	(18,223)	15,770
Other, net	14,840	8,371	(3,552)
Net change	(13,762)	2,904	(11,113)
Transfer of nuclear fuel disposal costs and related taxes from affiliated company	-	-	24,556
Energy adjustment clauses, net	10,329	(53,824)	(8,307)
Other, net	4,275	(8,940)	1,640
Net other sources (uses) of funds	842	(59,860)	6,776
Total Funds For Construction From Above Sources	505,529	457,220	534,887
Allowance For Equity Funds Used During Construction	87,383	67,958	41,694
GROSS PROPERTY ADDITIONS	$592,912	$525,178	$576,581
Composition of Gross Property Additions:			
Electric utility plant	$487,484	$446,644	$372,881
Gas utility plant	20,773	18,553	22,088
Nuclear fuel	84,655	59,981	181,612
Total	$592,912	$525,178	$576,581

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

The Connecticut Light and Power Company

BALANCE SHEETS

At December 31,	1984	1983
	(Thousands of Dollars)	
Assets		
Utility Plant, at original cost:		
Electric	$2,632,726	$2,559,158
Gas	256,968	238,674
	2,889,694	2,797,832
Less: Accumulated provision for depreciation.	965,357	885,383
	1,924,337	1,912,449
Construction work in progress (Note 8)	1,737,878	1,338,814
Nuclear fuel, net (Note 3)	271,827	244,755
Total net utility plant	3,934,042	3,496,018
Other Property and Investments:		
Investments in regional nuclear generating companies and subsidiary companies, at equity	49,701	49,693
Other, at cost	13,105	9,849
	62,806	59,542
Current Assets:		
Cash and special deposits (Note 2)	16,419	3,385
Receivables, less accumulated provision for uncollectible accounts of $7,674,000 in 1984 and $7,450,000 in 1983	166,782	161,375
Receivables from affiliated companies	57,300	23,298
Accrued utility revenues	81,761	81,032
Fuel, materials and supplies, at average cost	94,624	91,832
Recoverable energy costs	10,274	-
Prepayments and other	5,755	6,261
	432,915	367,183
Deferred Charges:		
Unamortized debt expense	6,632	4,926
Energy adjustment clauses, net	36,033	60,159
Unrecovered spent nuclear fuel disposal costs	12,301	18,996
Other	10,412	22,169
	65,378	106,250
Total Assets	$4,495,141	$4,028,993

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

The Connecticut Light and Power Company

BALANCE SHEETS

At December 31,	1984	1983
	(Thousands of Dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock - $10 par value. Authorized 24,500,000 shares; outstanding 12,222,930 shares..........	$ 122,229	$ 122,229
Capital surplus, paid in..........	613,397	583,361
Retained earnings..........	588,794	458,599
Total common stockholder's equity..........	1,324,420	1,164,189
Cumulative preferred stock - $50 par value. Authorized 9,000,000 shares; outstanding 7,861,905 shares in 1984 and 7,894,102 shares in 1983		
Not subject to mandatory redemption (Note 5).	256,195	256,195
Subject to mandatory redemption (Note 6).....	135,892	137,393
Long-term debt, net (Note 7)..........	1,819,516	1,685,374
Total capitalization..........	3,536,023	3,243,151
Obligations Under Capital Leases (Note 3)..........	256,262	227,794
Current Liabilities:		
Notes payable to banks (Note 2)..........	18,000	6,500
Commercial paper (Note 2)..........	-	16,500
Long-term debt and preferred stock-current portion..........	23,975	18,154
Obligations under capital leases - current portion (Note 3)..........	57,171	44,296
Accounts payable..........	66,512	70,726
Accounts payable to affiliated companies..........	49,003	59,950
Accrued taxes..........	100,936	58,413
Accrued interest..........	56,669	40,093
Other..........	16,975	14,033
	389,241	328,665
Deferred Credits:		
Accumulated deferred income taxes..........	121,910	128,528
Accumulated deferred investment tax credits......	181,284	91,523
Other..........	10,421	9,332
	313,615	229,383
Commitments and Contingencies (Note 8)		
Total Capitalization and Liabilities....	$4,495,141	$4,028,993

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

The Connecticut Light and Power Company

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Common Stock	Capital Surplus, Paid in	Retained Earnings	Total
	(Thousands of Dollars)			
Balance at January 1, 1982.........	$122,229	$396,282	$326,272	$ 844,783
Net income for 1982..............			152,960	152,960
Cash dividends on preferred stock...........................			(26,287)	(26,287)
Cash dividends on common stock...			(79,624)	(79,624)
Capital contribution from Northeast Utilities (parent company).......................		110,000		110,000
Preferred stock issuance and retirement expenses.............		(1,818)		(1,818)
Balance at December 31, 1982.......	122,229	504,464	373,321	1,000,014
Net income for 1983..............			227,207	227,207
Cash dividends on preferred stock...........................			(30,578)	(30,578)
Cash dividends on common stock...			(111,351)	(111,351)
Capital contribution from Northeast Utilities (parent company).......................		80,000		80,000
Preferred stock issuance and retirement expenses.............		(1,103)		(1,103)
Balance at December 31, 1983.......	122,229	583,361	458,599	1,164,189
Net income for 1984..............			284,227	284,227
Cash dividends on preferred stock...........................			(35,592)	(35,592)
Cash dividends on common stock...			(118,440)	(118,440)
Capital contribution from Northeast Utilities (parent company).......................		30,000		30,000
Gain on reacquired preferred stock net of issuance and retirement expenses.............		36		36
Balance at December 31, 1984 (a)...	$122,229	$613,397	$588,794	$1,324,420

(a) At December 31, 1984, there was approximately $319,194,000 of retained earnings available for payment of cash dividends on common stock under the provisions of the Company's First Mortgage Indenture and Deed of Trust.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: The Connecticut Light and Power Company (the Company), Western Massachusetts Electric Company (WMECO) and Holyoke Water Power Company (HWP) are the operating subsidiaries comprising the Northeast Utilities system (the system) and are wholly owned by Northeast Utilities (NU).

Other wholly owned subsidiaries of NU provide substantial support services to the system. Northeast Utilities Service Company supplies centralized accounting, administrative, data processing, engineering, financial, legal, operational, planning, purchasing and other services to the system companies. Northeast Nuclear Energy Company acts as agent for system companies in constructing and operating nuclear generating facilities. NU also has two subsidiary realty companies, The Rocky River Realty Company and The Quinnehtuk Company.

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 of various federal and state regulatory agencies.

Public Utility Regulation: NU is registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935, and it and its subsidiaries, including the Company, are subject to the provisions of the act. Arrangements among the 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. The Company is subject to further regulation for rates and other matters by the FERC and the Connecticut Department of Public Utility Control (DPUC), and follows the accounting policies prescribed by the respective commissions.

Investments: The Company owns common stock of four regional nuclear generating companies. These companies, with the Company's ownership interests, are:

Connecticut Yankee Atomic Power Company (CY)	34.5%
Yankee Atomic Electric Company	24.5%
Maine Yankee Atomic Power Company	12.0%
Vermont Yankee Nuclear Power Corporation (VYNPC)	9.5%

The Company's investments in these companies are accounted for on the equity basis. The electricity produced from these facilities is committed to the participants based on their ownership interests and is billed pursuant to contractual agreements.

Revenues: Utility revenues are based on authorized rates applied to each customer's use of electricity or gas. Rates can be increased only through a formal proceeding before the appropriate regulatory commission. At the end of each accounting period, the Company accrues an estimate for the amount of energy delivered but unbilled.

Spent Nuclear Fuel Disposal Costs: Under the Nuclear Waste Policy Act of 1982, the Company is paying the United States Department of Energy (DOE), on a quarterly basis, a fee of 1.0 mill per kilowatt-hour (kWh) based on the Company's share of nuclear generation beginning April 7, 1983, for the disposal of spent nuclear fuel and high-level radioactive waste.

For nuclear fuel used to generate electricity prior to April 7, 1983, the fees are based on the Company's share of the amount of energy extracted from such fuel. Fees due to the DOE for the disposal of nuclear fuel used prior to April 7, 1983, are approximately $66.6 million, excluding interest. The Company has until June 1985 to determine a payment arrangement for these fees. As of December 31, 1984, approximately $54.2 million has been collected through rates.

The DPUC has allowed for the recovery of spent nuclear fuel disposal costs through rates based on the provisions of the Nuclear Waste Policy Act of 1982.

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 net salvage value and removal costs as approved by the DPUC. 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 depreciation rates for the several classes of electric and gas plant in service are equivalent to the following composite rates:

Year	Electric	Gas
1984	3.5%	4.1%
1983	3.5	4.2
1982	3.5	2.8

Nuclear Decommissioning: A 1983 decommissioning study indicates that immediate dismantlement at retirement is the most viable and economic method of decommissioning the Millstone 1 and 2 nuclear units in which the Company has an 81 percent ownership interest. The Company's share of the total estimated cost of decommissioning these units is $219 million in year-end 1984 dollars. Decommissioning studies are reviewed and updated periodically to reflect changes in decommissioning requirements, technology and inflation. As of December 31, 1984, the Company has collected through rates $26.3 million for future decommissioning costs. Although a substantial portion of the estimated total decommissioning costs has been approved by regulatory agencies and is reflected in depreciation expense, the Company believes revenues in amounts higher than those currently being collected will be required to pay the full projected costs of decommissioning.

Income Taxes: The tax effect of timing differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of income subject to tax) is accounted for in accordance with the ratemaking treatment of the applicable regulatory commissions.

The Company did not provide deferred income taxes for certain timing differences during periods when the DPUC did not permit the recovery of such income taxes through rates charged to customers. The cumulative net amount of income tax timing differences for which deferred taxes have not been provided was approximately $921 million at December 31, 1984. As allowed under current regulatory practices, deferred taxes not previously provided are being collected in customers' rates as such taxes become payable.

Investment tax credits, which reduce federal income taxes currently payable, are deferred and amortized over the useful life of the related utility plant. At December 31, 1984, the Company had unused and unrecorded investment tax credits of approximately $3 million, which are available to offset federal income tax provisions through 1999. See Note 4 for the components of income tax expense.

Allowance for Funds Used During Construction (AFUDC): AFUDC represents the estimated cost of capital funds used to finance the Company's construction program. These costs, which are one component of the total capitalized cost of construction, generally are not recognized as part of the rate base for ratemaking purposes until facilities are placed in service. AFUDC is recovered over the service life of plant in the form of increased revenue collected as a result of higher depreciation expense.

In its December 1983 rate decision, the DPUC allowed the Company $19 million of revenues to support a portion of Millstone 3 construction costs in rate base. AFUDC is not applied to those construction costs.

The effective AFUDC rates for 1984, 1983, and 1982 were 9.3 percent, 9.2 percent, and 8.8 percent, respectively. These rates are calculated using the net-of-income tax method and in accordance with FERC guidelines.

Retirement Plan: The Company participates in the Northeast Utilities Service Company Retirement Plan (the Plan). The Plan, which covers all regular system employees, is noncontributory. The system's policy is to fund annually the actuarially determined contribution, which includes that year's normal cost, the amortization of prior years' actuarial gains or losses over 15 years, and the amortization of prior service cost over a period of 40 years. The Company's allocated portion of the system's pension cost, part of which was charged to utility plant, approximated $13.9 million in 1984, $15.2 million in 1983 and $13.1 million in 1982.

The actuarial present value of accumulated plan benefits and plan net assets available for benefits for the Plan is:

January 1,	1984	1983
	(Thousands of Dollars)	
Benefits:		
Vested..............	$310,498	$283,246
Nonvested...........	41,244	33,109
	$351,742	$316,355
Net assets available for benefits........	$446,949	$377,723

The assumed rate of return used to determine the actuarial present value of accumulated plan benefits was 7.5 percent for 1984 and 1983.

In addition to pension benefits, the Company provides certain health care and life insurance benefits to eligible retired employees. The cost of providing those benefits was approximately $2,949,000 in 1984, $2,695,000 in 1983 and $2,000,000 in 1982. The Company recognizes health care benefits primarily as incurred and provides for life insurance benefits through premiums paid to an insurance company.

Energy Adjustment Clauses: The Company's retail electric and gas rates include adjustment clauses under which fossil fuel prices and purchased power costs and purchased gas costs above or below base rate levels are charged or credited to customers. As prescribed by the DPUC, most differences between the Company's actual fossil fuel and purchased gas costs and the current cost recoveries are deferred until future recovery is permitted.

The Company's retail base electric rates include a 70 percent composite nuclear generation component. The DPUC has approved the use of a generation utilization adjustment clause which levels the effect on fuel costs caused by variations from a 70 percent composite nuclear generation capacity factor. When actual nuclear performance is above 70 percent, fuel costs are lower than amounts included in base rates, and when nuclear performance is below 70 percent, fuel costs are higher than amounts included in base rates. At the end of a 12-month period ending July 31 of each year, these net variations from the amounts included in base rate cost levels are refunded to or collected from customers over the subsequent 11-month period. Should the composite capacity factor fall below 55 percent, a public hearing is required before collection from customers is permitted.

2. SHORT-TERM DEBT

The Company and WMECO have joint credit lines of $350 million, pursuant to revolving credit/term loan agreements with two groups of banks. The maximum borrowing limit of the Company under the agreements is $350 million less amounts (not to exceed $105 million) borrowed by WMECO. The Company is obligated to pay commitment fees of up to three-eighths of 1 percent per annum on its proportionate share of the daily average of the unborrowed portion of the aggregate commitment. At December 31, 1984, the Company had no borrowings under these agreements.

The Company uses bank loans and commercial paper to assist in financing its continuing construction program on a short-term basis and to meet general working capital needs. The system companies have joint bank credit lines totaling $48 million. Terms call for interest rates not to exceed the prime rate during the borrowing term. Although these lines generally are renewable, the continuing availability of the unused lines of credit is subject to review by the banks involved. Compensating balances for the system companies are maintained in connection with these bank credit lines which, at December 31, 1984, amounted to $2.4 million. At December 31, 1984, the amount of unused available borrowing capacity under the credit lines available to the system companies was $46 million.

Cash and special deposits at December 31, 1984, included $14.6 million of restricted funds which must be used for future expenditures relating to the installation of pollution control equipment at Millstone 3 and Seabrook unit 1.

3. LEASES

The Company and WMECO have entered into a capital lease agreement to finance up to $530 million of nuclear fuel for Millstone 1 and 2 and their share for Millstone 3. The Company and WMECO make quarterly lease payments for the cost of nuclear fuel consumed in the reactors plus financing costs associated with the fuel in the reactors (based on a units-of-production method at rates which reflect estimated kWhs of energy provided). Upon permanent discharge from the reactors, ownership of the nuclear fuel transfers to the Company and WMECO.

The Company has also entered into lease agreements, some of which are capital leases, for the use of substation equipment, office equipment, vehicles, and office space. The provisions of these lease agreements generally provide for renewal options.

Commencing in 1984, the Company classified its leases in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 13, "Accounting for Leases" and SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," which required balance sheet recognition of capital leases. The adoption of SFAS No. 13 has been retroactively applied to the 1983 balance sheet. There is no effect on the

Company's results of operations. Following are the rental payments charged to operating expense:

Year	Capital Leases	Operating Leases
1984	$76,777,000	$22,073,000
1983	36,858,000	18,331,000
1982	6,167,000	15,620,000

Interest included in capital lease rental payments was $18,554,000 in 1984, $11,843,000 in 1983 and $2,139,000 in 1982.

Substantially all of the capital lease rental payments were made pursuant to the nuclear fuel lease agreement. Future minimum lease payments, under the nuclear fuel capital lease cannot be reasonably estimated on an annual basis due to variations in the usage of nuclear fuel.

Future minimum rental payments, excluding annual nuclear fuel lease payments and executory costs such as real estate taxes, state use taxes, insurance and maintenance, under long-term noncancelable leases as of December 31, 1984, are approximately:

Year	Capital Leases	Operating Leases
	(Thousands of Dollars)	
1985	$ 1,700	$ 19,000
1986	1,700	17,100
1987	1,700	11,700
1988	1,700	7,100
1989	1,600	4,600
After 1989	18,800	42,500
Future minimum lease payments	27,200	$102,000
Less amount representing interest	15,100	
Present value of future minimum lease payments for other than nuclear fuel	12,100	
Present value of future nuclear fuel lease payments	301,300	
Total	$313,400	

4. INCOME TAX EXPENSE

The components of the federal and state income tax provisions are:

For the Years Ended December 31,	1984	1983	1982
		(Thousands of Dollars)	
Current income taxes:			
Federal......................	$ 16,342	$ (1,245)	$ 3,552
State........................	32,886	(429)	16,958
Total current..............	49,228	(1,674)	20,510
Deferred income taxes, net:			
Investment taxes (credits)...	94,500	(8,525)	56,198
Federal......................	(1,437)	88,227	(9,132)
State........................	364	23,682	(3,324)
Total deferred............	93,427	103,384	43,742
Taxes on borrowed funds portion of AFUDC.....................	37,825	31,170	28,708
Total income tax expense..................	180,480	132,880	92,960
Less: Income taxes (credits) included in other income, net of the tax effects of the borrowed funds portion of AFUDC..	(2,405)	(2,768)	(2,281)
Income taxes charged to operating expenses........	$182,885	$135,648	$95,241

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

Investment tax credits.........	$94,500	$ (8,525)	$56,198
Liberalized depreciation, excluding leased nuclear fuel	14,287	14,616	9,309
Construction overheads.........	14,895	14,709	8,673
Liberalized depreciation and capitalized interest on leased nuclear fuel..........	326	21,583	-
Decommissioning costs..........	(4,647)	(923)	(2,002)
Settlement credits - nuclear fuel.................	(859)	(1,786)	(690)
Unbilled revenues..............	(1,483)	1,478	(310)
Energy adjustment clauses......	(14,658)	36,159	(21,748)
Spent nuclear fuel storage accruals....................	(4,248)	29,232	(837)
Canceled nuclear project.......	(1,877)	(773)	(1,121)
Deferred unusual operating expense............	(1,934)	(2,102)	(2,885)
Other..........................	(875)	(284)	(845)
Deferred income taxes, net.	$93,427	$103,384	$43,742

The effective income tax rate is computed by dividing total income tax expense by the sum of such taxes and net income. The differences between the effective rate and the federal statutory income tax rate are:

For the Years Ended December 31,	1984	1983	1982
Federal statutory income tax rate....	46.0%	46.0%	46.0%
Tax effect of differences:			
Additional depreciation for tax purposes........................	0.2	(0.5)	(2.6)
Allowance for equity funds used during construction - not recognized as income for tax purposes........................	(8.6)	(8.7)	(7.8)
Investment tax credit amortization..	(1.6)	(1.3)	(0.9)
State income taxes, net of federal benefit..........................	4.7	4.4	3.0
Reversal of current tax reserves no longer required................	-	(2.7)	-
Other, net..........................	(1.9)	(0.3)	0.1
Effective income tax rate............	38.8%	36.9%	37.8%

5. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Details of preferred stock not subject to mandatory redemption outstanding are:

Description	Current Redemption Price*	Shares Outstanding December 31, 1984	December 31, 1984	1983	1982
			(Thousands of Dollars)		
$1.90 Series of 1947............	$52.50	163,912	$ 8,196	$ 8,196	$ 8,196
$2.00 Series of 1947............	54.00	336,088	16,804	16,804	16,804
$2.04 Series of 1949............	52.00	100,000	5,000	5,000	5,000
$2.06 Series E of 1954..........	51.00	200,000	10,000	10,000	10,000
$2.09 Series F of 1955..........	51.00	100,000	5,000	5,000	5,000
$2.20 Series of 1949............	52.50	200,000	10,000	10,000	10,000
$3.24 Series G of 1968..........	51.84	300,000	15,000	15,000	15,000
$3.80 Series J of 1971..........	53.05*	400,000	20,000	20,000	20,000
$4.48 Series H of 1970..........	53.33*	300,000	15,000	15,000	15,000
$4.48 Series I of 1970..........	53.44*	400,000	20,000	20,000	20,000
$4.56 Series K of 1974..........	53.22*	1,000,000	50,000	50,000	50,000
3.90% Series of 1949............	50.50	160,000	8,000	8,000	8,000
4.50% Series of 1956............	50.75	104,000	5,200	5,200	5,200
4.50% Series of 1963............	50.50	160,000	8,000	8,000	8,000
4.96% Series of 1958............	50.50	100,000	5,000	5,000	5,000
5.28% Series of 1967............	51.43	200,000	10,000	10,000	10,000
6.56% Series of 1968............	51.44	200,000	10,000	10,000	10,000
7.60% Series of 1971............	52.56*	199,925	9,996	9,996	9,996
9.36% Series of 1970............	53.21*	200,000	10,000	10,000	10,000
9.60% Series of 1974............	53.46*	299,970	14,999	14,999	14,999
Total preferred stock not subject to mandatory redemption		5,123,895	$256,195	$256,195	$256,195

*Redemption prices reduce in future years.

All or any part of each outstanding series of preferred stock may be redeemed by the Company at any time at established redemption prices plus accrued dividends to the date of redemption.

6. PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

Details of preferred stock subject to mandatory redemption outstanding are:

Description	Current Redemption Price*	Shares Outstanding December 31, 1984	December 31, 1984	1983	1982
			(Thousands of Dollars)		
$5.52 Series L of 1975	$54.14	292,099	$ 14,657	$ 15,770	$16,140
10.48% Series of 1980	55.24	500,000	25,000	25,000	25,000
11.52% Series of 1975	54.32	145,911	7,321	7,776	8,321
15.04% Series M of 1982	57.52	800,000	40,000	40,000	40,000
Adjustable Rate Series N of 1983	56.15	1,000,000	50,000	50,000	-
		2,738,010			
Less preferred stock to be redeemed within one year			1,086	1,153	568
Total preferred stock subject to mandatory redemption			$135,892	$137,393	$88,893

At December 31, 1984, there were 8,000,000 shares of $25 par value preferred stock authorized and unissued.

*Redemption prices reduce in future years.

The $5.52 Series L of 1975 preferred stock ($5.52 Series) requires a sinking-fund sufficient to retire a minimum of 20,000 shares (or a maximum of 40,000 shares) at $50 per share each year. During 1984, 1983 and 1982 the Company had reacquisitions of the $5.52 Series of 22,966 shares, 5,290 shares, and 32,536 shares, respectively. The 10.48% Series of 1980 preferred stock (10.48% Series) requires a sinking-fund sufficient to retire a minimum of 20,000 shares (or a maximum of 40,000 shares) at $50 per share each year commencing July 1, 1986. There were no changes during 1984, 1983 and 1982 in the 10.48% Series. The 11.52% Series of 1975 preferred stock (11.52% Series) requires a sinking-fund sufficient to retire a minimum of 10,000 shares (or a maximum of 20,000 shares) at $50 per share each year. During 1984, 1983 and 1982, the Company had reacquisitions of the 11.52% Series of 9,231 shares, 11,103 shares and 11,576 shares, respectively. The 15.04% Series M of 1982 preferred stock (15.04% Series) requires a sinking-fund sufficient to retire a minimum of 40,000 shares (or a maximum of 80,000 shares) at $50 per share each year commencing June 1, 1988. There were no changes in 1984, 1983 and 1982 in the 15.04% Series. The Adjustable Rate Series N of 1983 preferred stock (Adjustable Rate Series) requires a sinking-fund sufficient to retire a minimum of 50,000 shares (or a maximum of 100,000 shares) at $50 per share each year commencing October 1, 1988. There was no change in 1984 and 1983 in the Adjustable Rate Series.

The minimum sinking-fund provisions of the series subject to mandatory redemption, for the years 1985 through 1989, aggregate $1,500,000 in 1985, $2,500,000 in 1986 and 1987, and $7,000,000 in 1988 and 1989. All sinking fund requirements for the preferred stoc' subject to mandatory redemption have been met. 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. Any dividend payment in arrears on outstanding shares of preferred stock would prohibit the redemption or purchase of less than all of the preferred stock outstanding. All or part of either the $5.52 Series, the 10.48% Series, the 11.52% Series, the 15.04% Series or the Adjustable Rate Series may be redeemed by the Company at any time at established redemption prices plus accrued dividends to the date of redemption except that during the initial five-year redemption period the above series of preferred stock are subject to certain refunding limitations.

7. LONG-TERM DEBT

Details of long-term debt outstanding are:

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
First Mortgage Bonds:		
2 3/4% Series L, due 1984..............	$ -	$ 10,000
3 1/4% Series N, due 1985..............	20,000	20,000
3 7/8% Series O, due 1988..............	30,000	30,000
4 7/8% Series P, due 1990..............	25,000	25,000
4 1/2% Series Q, due 1986..............	9,600	9,600
4 3/8% Series R, due 1993..............	25,000	25,000
6 % Series S, due 1997..............	30,000	30,000
6 1/2% Series T, due 1998..............	20,000	20,000
6 7/8% Series U, due 1998..............	40,000	40,000
8 3/4% Series V, due 2000..............	40,000	40,000
8 7/8% Series W, due 2000..............	40,000	40,000
7 3/8% Series X, due 2001..............	30,000	30,000
7 5/8% Series Y, due 2002..............	50,000	50,000
7 5/8% Series Z, due 2003..............	50,000	50,000
8 3/4% Series AA, due 2004..............	65,000	65,000
11 % Series CC, due 2000	39,304	39,680
8 7/8% Series DD, due 2007..............	45,000	45,000
9 1/4% Series EE, due 2008..............	40,000	40,000
14 3/8% Series FF, due 2010..............	65,000	65,000
17 3/4% Series GG, due 1991..............	65,000	65,000
15 % Series HH, due 2012..............	100,000	100,000
12 1/4% Series II, due 1993..............	85,000	85,000
12 3/8% Series JJ, due 1994..............	75,000	-
3 1/8% Series D, due 1984..............	-	6,969
5 % Series, due 1987.................	15,000	15,000
4 3/8% Series E, due 1988..............	18,000	18,000
4 1/4% Series, due 1993.................	15,000	15,000
4 1/2% Series, due 1994.................	12,000	12,000
5 5/8% Series, due 1997.................	20,000	20,000
6 1/2% Series, due 1998.................	10,000	10,000
7 1/8% Series, due 1998.................	25,000	25,000
9 1/4% Series, due 2000.................	20,000	20,000
7 5/8% Series, due 2001.................	30,000	30,000
7 1/2% Series, due 2002.................	35,000	35,000
7 1/2% Series, due 2003.................	40,000	40,000
9 1/4% Series, due 2004.................	30,000	30,000
11 1/2% Series, due 1995.................	19,804	20,186
9 3/8% Series, due 2008.................	40,000	40,000
13.35 % Series, due 1990.................	10,000	10,000
17.60 % Series, due 1989.................	20,000	20,000
15 5/8% Series, due 1992.................	40,000	40,000
Total First Mortgage Bonds..........	$1,388,708	$1,331,435

	December 31, 1984	December 31, 1983
	(Thousands of Dollars)	
Term Loan Agreements:		
Secured note, variable rate due 1988-1991	$ 150,000	$ 150,000
14.80%, due 1991	75,000	-
Millstone 3 Construction Trust, variable rate	49,865	122,695
Pollution Control Notes:		
5.90%, due 1998	9,437	9,437
6.50%, due 2007	16,000	16,000
Variable rate, due 2013-2014	90,800	10,000
Fees due for spent fuel disposal costs.	66,553	66,553
Other	62	94
Less amounts due within one year	22,889	17,001
Unamortized premium and discount, net..	(4,020)	(3,839)
Long-term debt, net	$1,819,516	$1,685,374

The Company and WMECO participate in a construction trust arrangement to assist in the financing of the Millstone 3 construction. Obligations under this arrangement are initially limited to $400 million. The trust was given a lien, junior to the lien of the Company's indenture, on the Company's interest in Millstone 3. Once Millstone 3 is in service, but beginning no later than 1988, the trust obligations are to be repaid over a four-year period.

Interest costs of $7.9 million during 1984, $9.9 million during 1983 and $6.1 million during 1982 were incurred and capitalized, net of income taxes, by the Company. The weighted average interest rate charged to the system by the trust was 11.5 percent in 1984, 10.8 percent in 1983 and 10.7 percent in 1982.

Long-term debt maturities and cash sinking-fund requirements on debt outstanding at December 31, 1984, for the years 1985 through 1989, are: $24,406,000, $14,006,000, $19,391,000, $90,523,000 and $62,523,000, respectively. In addition, there are annual 1 percent sinking- and improvement-fund requirements, currently amounting to $12,206,000, $12,163,000, $12,119,000, $12,075,000 and $12,031,000 for the years 1985 through 1989, respectively. Such sinking- and improvement-fund requirements may be satisfied by the deposit of cash or bonds or by certification of property additions.

All or any part of each outstanding series of first mortgage bonds may be redeemed by the Company at any time at established redemption prices plus accrued interest to the date of redemption, except certain series which are subject to certain refunding limitations during their respective initial five-year redemption periods. The 11% Series CC bonds require a sinking-fund sufficient to retire a minimum of $2,500,000 in principal amount each year. The 11 1/2% Series bonds require a sinking-fund sufficient to retire a minimum of $1,875,000 in principal amount each year.

Essentially all of the Company's utility plant is subject to the lien of its first mortgage bond indentures.

8. COMMITMENTS AND CONTINGENCIES

Construction Program: The Company is engaged in a continuous construction program and currently forecasts construction expenditures (including AFUDC) of $1.4 billion for the years 1985-1989, including $579 million for 1985. In addition, the Company estimates that nuclear fuel requirements will be $253.8 million for the years 1985-1989, including $55.4 million for 1985.

The construction program is subject to periodic review and revision, and actual construction expenditures may vary from such estimates due to factors such as revised load estimates, inflation, revised nuclear safety regulations, delays, difficulties in the licensing process, the availability and cost of capital, and the granting of timely and adequate rate relief by regulatory commissions, as well as actions by other regulatory bodies.

Millstone 3: At December 31, 1984, the Company's construction work in progress (CWIP) included an investment of $1.51 billion in Millstone 3. The unit is scheduled to be placed in service in May 1986. The Company projects that the construction cost of Millstone 3 will exceed the 1982 estimate of $3.54 billion. The Company is now using a projected cost for the unit of $3.825 billion. The Company's share would represent an investment of $2.01 billion, based on its ownership share of 52.6115 percent.

In 1983, the Connecticut Legislature enacted a law limiting, with certain exceptions, the construction costs of Millstone 3 that may be included in a Connecticut electric company's rate base to $3.54 billion. The Company is not able at this time to determine how much, if any, of the total cost of Millstone 3 would not be recoverable because of this law. Should it be determined that the law prevents the Company from recovering its prudent investment in Millstone 3, management intends to pursue appropriate measures, which could include seeking legislative change or administrative and court appeals to obtain full rate recognition of its prudent investment.

During 1985, the Company expects to file rate applications in its retail and wholesale jurisdictions to reflect appropriate rate recognition of Millstone 3 costs when the unit begins commercial operation. The Company believes that it is entitled to full rate recognition of its prudently incurred investment in Millstone 3 at the time the unit begins commercial operation. Because the rate levels necessary to support such full recognition will be substantially higher than the Company's current rates, the Company expects the DPUC will consider requiring the costs associated with Millstone 3 be phased into rates over a limited number of years after the unit enters service.

As part of required periodic management audits of utility companies, the DPUC engaged a management consulting firm to conduct a comprehensive audit of the prudence of the management and construction of Millstone 3. The audit will be conducted in two phases. The first phase will review the conduct of the project through September 30, 1984, and the second phase will review the project to completion. The first phase review is expected to be completed in mid-1985.

Many of the joint owners of Millstone 3 are also joint owners of the Seabrook project (see "Seabrook" note following). Should any of the joint owners fail to meet their obligation for the construction of Millstone 3, the Company and WMECO have developed contingent financing plans to help assure that adequate resources will be available to complete the construction of Millstone 3.

Seabrook: The Company has a 4.1 percent joint ownership interest in the two nuclear units in Seabrook, New Hampshire. At December 31, 1984, the Company's CWIP balance included an investment of approximately $135 million in Seabrook unit 1 and approximately $24 million in Seabrook unit 2. The Company projects that the cost to complete its share of Seabrook unit 1 will be approximately $77 million, which is higher than the cost estimate being used by the Seabrook project management.

In 1984, the DPUC established a $4.7 billion limit, with certain exceptions, on the construction costs of Seabrook unit 1 that may be made part of rate base or otherwise included in rates of the Company. The Company believes that a limit on prudently incurred costs would not meet constitutional standards and has appealed the DPUC's decision to the Superior Court.

In April 1984, construction of both Seabrook units was suspended shortly after the announcement of new cost and schedule estimates for both units. In July 1984, construction of Seabrook unit 1 was resumed. The DPUC conducted hearings on the economic viability of Seabrook unit 1 and in November 1984, determined that Seabrook unit 1 is economically and financially viable, is more desirable than cancellation, and its completion is in the public interest. Uncertainties such as the outcome of pending regulatory proceedings in states other than Connecticut, the ability of the various joint owners to make necessary financing arrangements, intervenor challenges and risks attendant to the licensing process could cause further delays. Completion of the unit, therefore, is not assured. Construction of Seabrook unit 2 has not been resumed. In a recent rate order for another Connecticut utility, the DPUC concluded that Seabrook unit 2 was effectively, if not technically, canceled. The Company will apply to the DPUC for recovery of its Seabrook unit 2 investment. If Seabrook unit 1 were to be canceled, the Company would also seek recovery.

The Company cannot predict whether and to what extent full recovery of its Seabrook investments will be permitted. However, the Company believes that its Seabrook investments are recoverable based on past DPUC practices and previous DPUC orders with respect to Seabrook.

Hydro-Quebec: The Company, WMECO and HWP, along with other New England Utilities, have entered into agreements related to the financing and construction of transmission and terminal facilities (Phase I) to import hydropower from the Hydro-Quebec System in Canada. The Company has a 19.5 percent interest in such facilities and will be responsible for its share of the total annual costs of the facilities when completed. The current construction forecast is $167.9 million, of which $38 million has been expended as of December 31, 1984. A mid-1986 in-service date is planned for Phase I.

Nuclear Insurance Contingencies: The Price-Anderson Act currently limits public liability from a single incident at a nuclear power plant to $620 million. The first $160 million of liability would be covered by the maximum provided by private pool insurance. The additional liability of $460 million would be provided by an assessment of $5 million per incident levied on each of the 92 nuclear units operating in the United States, subject to a maximum assessment of $10 million per nuclear unit in any year. Based on the Company's ownership interests in the nuclear units currently in service, the maximum liability per incident would be $12.1 million, limited to a maximum of $24.2 million in any year.

Insurance has been purchased from Nuclear Electric Insurance Limited (NEIL) to cover (a) certain extra costs incurred in obtaining replacement power during a prolonged accidental outage with respect to the Company's ownership interests in Millstone 1 and 2 and CY; and (b) the cost of repair, replacement or decontamination of Company property resulting from insured events at Millstone 1, 2 and 3, CY, Maine Yankee Atomic Power Company and Vermont Yankee Nuclear Power Corporation. All companies insured with NEIL are subject to retroactive assessments if losses exceed the accumulated funds available to NEIL. The maximum potential assessments against the Company with respect to losses arising during current policy years are approximately $14.6 million under the replacement power policy and $13.8 million under the property damage and decontamination policy. Although the Company has purchased the limits of coverage currently available from conventional nuclear insurance pools, the cost of a nuclear incident could exceed available insurance proceeds.

Financial Arrangements for the Regional Nuclear Generating Companies: The owners of CY, including the Company, have agreed to purchase their pro rata shares of up to $40 million of CY's subordinated notes. The Company's share of the notes aggregate $13.8 million. As of December 31, 1984, there were no notes outstanding. This obligation will terminate in October 1985.

The owners of CY, including the Company, have guaranteed their pro rata shares of $44 million 17% Series A Debentures. The guarantee of the Company under this arrangement aggregates $15.9 million.

The owners of VYNPC, including the Company, have guaranteed their pro rata shares of a $40 million nuclear fuel financing through the Vernon Energy Trust. The guarantee of the Company aggregates $3.8 million.

The Company may be asked to provide additional capital and/or other types of direct or indirect financial support for one or more of the regional nuclear generating companies.

9. SEGMENTS OF BUSINESS

The following summarizes information relating to the Company's electric and gas operations:

For the Years Ended December 31,	1984	1983	1982
	(Thousands of Dollars)		
Operating information:			
Operating revenues-			
Electric	$1,554,808	$1,358,625	$1,278,198
Gas	224,430	238,999	224,447
Total	$1,779,238	$1,597,624	$1,502,645
Operating expenses excluding provisions for income taxes-			
Electric	$1,119,695	$1,013,964	$1,004,367
Gas	185,080	200,917	198,378
Total	$1,304,775	$1,214,881	$1,202,745
Pretax operating income-			
Electric	$ 435,113	$ 344,661	$ 273,831
Gas	39,350	38,082	26,069
Total	$ 474,463	$ 382,743	$ 299,900
Provision for income taxes-			
Electric	$ 167,279	$ 119,578	$ 87,819
Gas	15,606	16,070	7,422
Total	$ 182,885	$ 135,648	$ 95,241
Operating income-			
Electric	$ 267,835	$ 225,083	$ 186,012
Gas	23,743	22,012	18,647
Total	$ 291,578	$ 247,095	$ 204,659
Depreciation expense-			
Electric	$ 89,455	$ 85,860	$ 82,351
Gas	10,056	9,719	5,794
Total	$ 99,511	$ 95,579	$ 88,145
Gross Property Additions:			
Electric	$ 572,139	$ 506,625	$ 554,493
Gas	20,773	18,553	22,088
Total	$ 592,912	$ 525,178	$ 576,581

For the Years Ended December 31,	1984	1983	1982
	(Thousands of Dollars)		
Investment information at December 31:			
Identifiable assets (a) -			
Electric	$3,755,861	$3,326,103	$2,888,086
Gas	207,872	195,854	186,417
Nonallocable assets	531,408	507,036	441,429
Total Assets	$4,495,141	$4,028,993	$3,515,932

(a) Includes construction work in progress, materials and supplies, and allocated common utility plant.

10. IMPACT OF CHANGING PRICES (UNAUDITED)

The following supplementary data was prepared in accordance with the requirements of SFAS No. 33, "Financial Reporting and Changing Prices."

The methodology prescribed by SFAS No. 33, as amended, involves numerous assumptions and estimates and, therefore, the resulting information should be viewed as an approximation of the effects of inflation rather than a precise measure.

As required by SFAS No. 33, the historical cost of plant, as stated in the Company's financial records, is adjusted for changing prices. This adjustment reflects the changing prices of plant from the date plant was placed in service to the present. This price adjustment does not necessarily represent the replacement cost of existing plant because such plant is not expected to be replaced precisely in kind. Specific prices may increase more or less rapidly than the general rate of inflation. The Company's price adjustment was determined by indexing historical plant using the Handy-Whitman Index of Public Utility Construction Costs. Nuclear fuel accounts reflect the current replacement cost of such fuel based on current market prices. Land was estimated by using the Consumer Price Index for all Urban Consumers.

Depreciation expense was determined by applying the Company's depreciation rates to adjusted plant amounts. Other expense items were not adjusted because they were considered to be at average price levels for the year or were specifically excluded from adjustment by SFAS No. 33.

As a result of the adjustment to depreciation, net income was reduced by $117 million. The Company will eventually replace its plant assets at prices many times greater than the original historical cost even though it is unable to recover the replacement value of these assets through depreciation. At December 31, 1984, the current cost of fixed assets, net of accumulated depreciation, was $5.9 billion, while historical cost, or net cost recoverable through depreciation, was $3.9 billion. For 1984, the increase in general inflation ($220 million) exceeded the increase in specific prices ($77 million) after adjustment to net recoverable cost by $25 million.

During periods of inflation, holders of net monetary assets suffer a loss of purchasing power, while holders of net monetary liabilities experience a gain because debt will be repaid in dollars having less purchasing power. As a result of the substantial amount of debt which was used to finance utility plant, the Company's gain from the decline in purchasing power of net amounts owed was $97 million. This "gain" is not realizable by the Company, and therefore, cannot be considered additional funds for reinvestment or dividend distribution.

Comparison of Selected Financial Data
Adjusted for Changing Prices
(In Average 1984 Dollars, Except Historical Amounts)

Years Ended December 31,	1984	1983	1982	1981	1980
		(Millions of Dollars, except index data)			
Operating revenues:					
Historical	$1,779	$1,598	$1,503	$1,366	$1,104
Adjusted for changing prices	1,779	1,663	1,617	1,560	1,391
Net income (loss) (Excluding adjustment to net recoverable cost):					
Historical	$ 284	$ 227	$ 153	$ 105	$ 102
Adjusted for changing prices	167	98	20	(28)	14
Net assets at year-end:					
Historical	$1,324	$1,164	$1,000	$ 845	$ 812
Adjusted for changing prices	1,306	1,191	1,064	934	977
Amount by which the increase in general price level is greater than (or less than) the increase in specific prices after adjustment to net recoverable cost	$ 25	$ (14)	$ (35)	$ 71	$ 205
Gain from decline in purchasing power of net amounts owed	$ 97	$ 83	$ 75	$ 166	$ 232
Average consumer price index	311.1	298.4	289.1	272.4	246.8

Auditors' Report

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

We have examined the balance sheets of The Connecticut Light and Power Company (a Connecticut corporation and a wholly owned subsidiary of Northeast Utilities) as of December 31, 1984 and 1983, and the related statements of income, common stockholder's equity and sources of funds for gross property additions for each of the three years in the period ended December 31, 1984. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the financial position of The Connecticut Light and Power Company as of December 31, 1984 and 1983, and the results of its operations and the sources of funds for gross property additions for each of the three years in the period ended December 31, 1984, in conformity with generally accepted accounting principles applied on a consistent basis after giving retroactive effect to the change, with which we concur, in the method of accounting for capital leases as described in Note 3 of Notes to Financial Statements.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut,
February 18, 1985.

SELECTED FINANCIAL DATA

Years Ended December 31,	1984	1983	1982	1981	1980
		(Thousands of Dollars)			
Operating Revenues....	$1,779,238	$1,597,624	$1,502,645	$1,365,653	$1,103,896
Operating Income......	291,578	247,095	204,659	174,890	153,618
Net Income...........	284,227	227,207	152,960	104,568	102,143
Total Assets..........	4,495,141	4,028,993	3,478,644	3,116,424	2,863,659
Long-Term Debt*.......	1,842,405	1,702,375	1,523,182	1,416,710	1,207,407
Preferred Stock Subject to Mandatory Redemption*..........	136,978	138,546	89,461	51,601	53,209
Obligations Under Capital Leases*......	313,433	272,090	232,428	11,810	10,522

*Includes portions due within one year.

STATEMENTS OF QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
1984	March 31	June 30	September 30	December 31
	(Thousands of Dollars)			
Operating Revenues....	$498,938	$405,855	$426,902	$447,543
Operating Income......	$ 91,360	$ 59,040	$ 73,880	$ 67,298
Net Income...........	$ 87,310	$ 56,245	$ 73,415	$ 67,257
1983				
Operating Revenues....	$437,782	$355,177	$386,325	$418,340
Operating Income......	$ 76,780	$ 51,980	$ 58,085	$ 60,250
Net Income...........	$ 69,936	$ 45,562	$ 53,931	$ 57,778

STATISTICS

At December 31,	1984	1983	1982	1981	1980
Electric:					
Operating Revenues (thousands).......	$1,554,808	$1,358,625	$1,278,198	$1,184,385	$ 958,512
kWh Sales (millions)........	17,502	16,639	15,950	16,779	16,736
Customers (average).........	941,839	925,193	916,525	906,688	896,997
Gas:					
Operating Revenues (thousands).......	$ 224,430	$ 238,999	$ 224,447	$ 181,268	$ 145,384
Average Annual Residential kWh Use...............	7,648	7,533	7,408	7,588	7,697
Cubic Feet of Gas Sales (millions)..	29,682	27,661	28,917	29,029	27,546
Average Annual Residential Cubic Feet of gas Used..	72,303	68,296	75,030	77,449	75,882
Customers (average)	156,452	154,808	152,329	150,901	148,574
Utility Plant (thousands)........	$4,899,399	$4,381,401	$3,858,064	$3,336,776	$3,062,254
Employees (December 31)......	4,077	4,091	4,115	4,063	4,008

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 10015

The First National Bank of Boston, Corporate Trust Department
P.P. Box 1897, Boston, Massachusetts 02105

Preferred Stock
Transfer Agent, Dividend Disbursing Agent and Registrar
The Connecticut Bank and Trust Company, N.A. Stock Transfer Department
One Constitution Plaza, Hartford, Connecticut 06115

Dividend Payment Dates
5.28%, 9.60%, 10.48%, 11.52%,
$3.24, $4.48 H, $4.48 I and Adjustable Rate N Series -
January 1, April 1, July 1, and October 1
4.50%, 4.96%, 6.56%, 9.36%,
$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), 7.60%, 15.04%,
$3.80, $4.56, and $5.52 Series - March 1, June 1,
September 1, and December 1

Address General Correspondence in Care of:

Northeast Utilities Service Company
Investor Relations Department
P.O. Box 270
Hartford, Connecticut 06141-0270
Tel. (203) 665-5000

General Office
Selden Street, Berlin, Connecticut

The data contained in this Report is submitted for the sole purpose of providing information to present stockholders about the Company.

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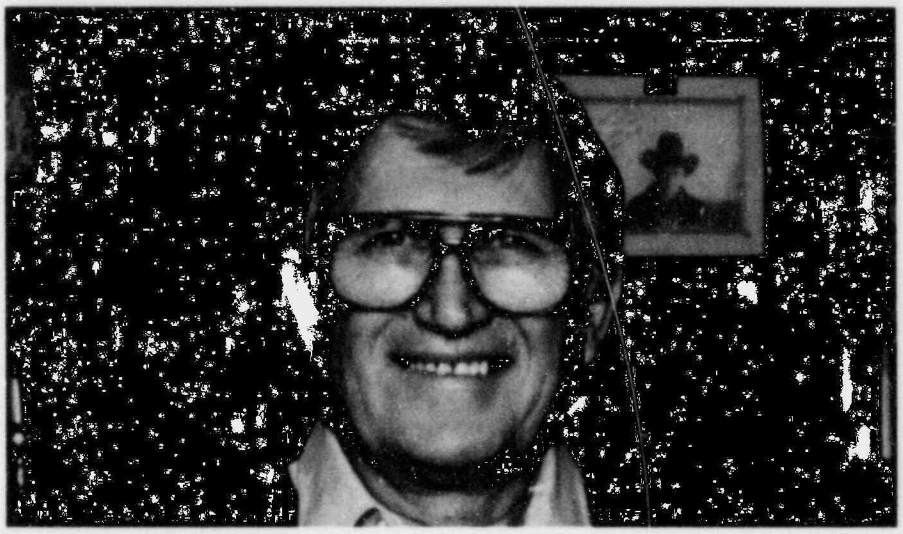
NORTHEAST UTILITIES

NU

THE CONNECTICUT LIGHT AND POWER COMPANY
WESTERN MASSACHUSETTS ELECTRIC COMPANY
HOLYOKE WATER POWER COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
NORTHEAST NUCLEAR ENERGY COMPANY

Commonwealth Energy System 1984 Annual Report



COM/Energy

System Profile

Commonwealth Energy System is an exempt public utility holding company with investments in four operating public utility companies located in central and eastern Massachusetts. System electric operations are involved in the production and sale of electricity in 41 communities including New Bedford, Plymouth, Cambridge and the geographic area comprising Cape Cod. Gas operations serve 47 communities including New Bedford, Cambridge and Worcester.

In addition to the utility companies, the system includes a steam distribution company, five real estate trusts and a company engaged in the operation of LNG facilities serving our gas division. The System also has a 34.5% ownership interest in a gas transmission and supply company. The retail electric subsidiaries receive capacity and energy from their respective ownership interests in one oil-fired and four nuclear electric generating facilities.

The System is a business trust organized in 1926 under the laws of Massachusetts. Subsidiaries of the System have common executive and financial management and receive technical assistance as well as financial, data processing, accounting, legal, corporate planning and other services from a service company subsidiary.

Annual Meeting

All shareholders are invited to attend the next Annual Meeting which will be held on May 2, 1985. A formal notice of the meeting together with a proxy statement and a form of proxy will be mailed on or about April 1, 1985 to shareholders entitled to vote at the meeting.

[illegible]

Financial Highlights

	1984	1983
Financial Statistics		
Total Operating Revenues	**$723,647,000**	$619,655,000
Total Operating Expenses	**680,192,000**	575,882,000
Net Income	**44,968,000**	42,728,000
Earnings Applicable to Common Shares	**41,545,000**	39,127,000
Property Plant and Equipment (including Work in Progress, net)	**741,710,000**	718,038,000
Construction Expenditures	**58,560,000**	61,082,000
Common Stock Data		
Earnings Per Common Share	**$4.75**	$4.63
Common Share Dividend Rate at End of Year	**$2.32**	$2.12
Weighted Average Common Shares Outstanding	**8,747,626**	8,451,316
Common Shareholders	**22,218**	23,277
Operating Statistics		
Customers Served		
Electric (including seasonal)	**296,000**	287,000
Gas	**205,000**	202,000
Unit Sales (in thousands)		
KWH—Retail	**3,552,535**	3,349,755
Wholesale	**2,557,652**	1,396,427
MCF— Firm	**32,568**	30,830
Interruptible	**4,741**	4,717

Contents

To Our Shareholders:

Financially, 1984 was the most successful year in our System's fifty-eight year history: earnings of $4.75 per common share topped our previous annual high of $4.63, attained just last year; operating revenues reached the $700 million mark for the first time and the market price of our common shares hit an all-time trading high of $25.50. In addition to these records, the system provided 100% of its 1984 construction requirements with internally generated funds and improved interest coverages. Standard and Poor's also raised the bond ratings of each of our electric subsidiaries.

These financial achievements are even more impressive when you consider that it has been more than two years since our operating subsidiaries received any rate increases. In fact, one of our retail electric subsidiaries voluntarily reduced rates by more than $2.4 million on an annual basis.

Our earnings increase would not have been achieved without recognition of approximately $4.3 million of a total $6.1 million after-tax gain realized in connection with the sale of our corporate headquarters office complex. Further, continued growth patterns of our retail gas and electric sales combined with the stabilization of inflation and interest rates contributed to the positive results.

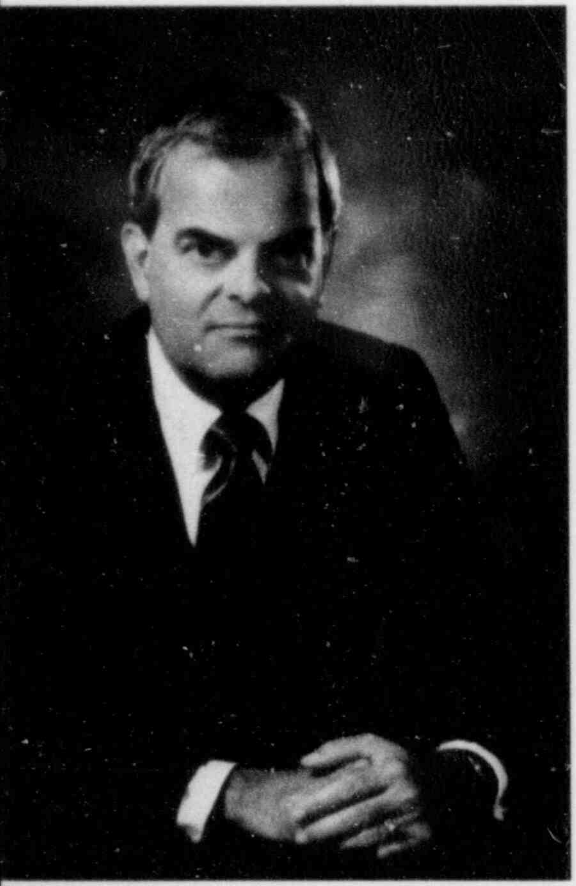
Consistent with the level of our financial performance and our goal of providing an attractive return for our shareholders, the Board of Trustees raised the quarterly dividend rate by five cents, effective August 1, 1984, to 58¢ or $2.32 on an annual basis.

In December, Canal Electric Company's Board of Directors voted to abandon the Company's investment in Seabrook Unit 2. While we believe that this action was necessary and appropriate under present circumstances, we are extremely concerned about the unavailability of this base load unit and its long-range impact on the economic and energy future of the New England region. Presently, the six-state region's population is growing at an average annual rate of 3.5% and its unemployment rate is well below the national average. Here in Massachusetts, 40,000 new businesses have started-up over the past two years and in 1984 a postwar record 140,000 new jobs were created which lowered the state's unemployment rate to a fourteen-year low of 4.8%. Most economists forecast that 1985 will be another favorable year for the New England economy resulting in a further reduction in the Massachusetts unemployment rate. This picture of economic health is a total reversal of the struggling economic scenario of the mid and late 1970's. While there are any number of factors which can effect shifts in the economy, we believe that energy prices have and will continue to have a significant favorable impact on the regional economy.

An analysis of our electric retail sales for the years 1982 through 1984 reveals that our sales have grown in concert with the region's recent economic expansion and increased consumption. Greater use by customers reflects the recent stability of energy prices and probably represents a change in consumer attitudes toward the relative value of our product. A recently issued research report confirmed our findings by stating that utilities now top the public's volunteered list of "best buys" and that an overwhelming majority of those surveyed think that electricity provides more value than any other household budget item.

Confronted with a growth-oriented economic outlook and renewed product appeal, our supply planning becomes increasingly important. It is obvious that the time for planning our future energy needs is indeed short with lead times for the construction of new generating facilities in the ten to fifteen year range. Solutions? Well, some of today's so-called "energy experts" would have us believe that Canadian power is our energy panacea. And if our industry is forced to abdicate its responsibility as an energy provider, Canadian power may very well be our only energy option at prices which will be beyond our control. However, before the Canadian landscape becomes overrun with power lines leading to the United States, let us consider the consequences of importing energy. This nation still imports 32% of its oil; even in today's soft oil market, these imports represent three-fourths of the 1983 national trade deficit. Displacing oil imports with another form of foreign energy certainly won't cure our national trade deficit nor will it narrow our vulnerability to future price increases or energy shortages.

Our precarious energy position is especially appalling when you consider that this country, which first harnessed the atom and had a twenty-year head start in nuclear energy, now ranks last among the nations which develop nuclear power. How did we fall from our energy leadership position? I believe the Seabrook project is a classic example of our decline. This project has endured numerous court battles, a constant stream of complex regulations and has been dragged through a multitude of political arenas resulting in unnecessary cost escalations and an understandable



skittishness among investors and bankers.

Reshaping our slumping energy posture is an achievable goal! However, a goal of energy independence would require a firm national commitment and the financial impetus necessary to resurrect some of this country's previously cancelled or mothballed nuclear projects. Admittedly, this could result in some short-term price increases, but building our own energy future will ultimately be cheaper than continued reliance on foreign oil or a shift to other countries as a source of energy supply. Our industry and the financial community must have reasonable assurances that the positive economics of major energy projects will not evaporate once plans leave the drawing board.

Despite the repeated efforts of special interest groups and some members of Congress to neutralize the Natural Gas Policy Act of 1978 (NGPA), price controls on new gas were phased-out, as scheduled, on January 1, 1985. The critics' predictions of endless price increases have not materialized because NGPA has worked. The price increases permitted in the earlier stages of NGPA provided the necessary incentive for gas producers to seek new supplies. Today, as a result of NGPA, the nation's current gas supply has improved to the point where there is an abundance in the marketplace. This positive supply picture is likely to continue through the balance of this decade and, according to the Department of Energy, result in price increases below the general rate of inflation.

Projecting the impact of the national supply picture in terms of our system, we anticipate that our supplies will expand as new gas is made available and as the terms of current gas purchase contracts are renegotiated. While some of the additional quantities will be used to meet normal increases in demand, we will also be in a position to continue our aggressive marketing posture.

Along with the expansion of our firm gas supply, I am pleased to report that, effective January 1, 1985, Hopkinton LNG Corp. became a wholly-owned subsidiary of the System. The purchase of Air Products and Chemicals' 50% equity interest provides added assurance that this peak-shaving facility will continue to play a critical role in our future gas supply strategy.

Over the last few years our communications with you have highlighted our customers, their products and the areas we serve. This year we intend to focus on you — our shareholders.

In exchange for your investment, which provides the necessary financial support for the continued delivery of services to our customers, the System strives to satisfy your investment goals with a reasonable, risk-adjusted return. However, we realize that our obligation to you goes well beyond earnings and dividends. We are here to keep you apprised of current developments concerning our System and industry and, to serve your needs. As a means of better serving you, the System is instituting a "Shareholder Awareness Program". Our goal is to find out more about you, your concerns and questions and the future direction you think the System should take. As a start, we would ask that you please take a few minutes to fill out the questionnaire located on the inside of the back cover of this report. The success of this program will rely heavily on your input.

In closing, I would like to express my personal gratitude to our employees for their contribution to our success and to you, our shareholders, for your continued financial support.

For the Trustees,

G E Anderson

G. E. Anderson,
President and Chief Executive Officer

Shareholder Information

Ever since our stock was first traded, you have played an ever-increasing role in our growth and success. We recognize our responsibilities as custodian of your investment dollars and are truly interested in learning more about you. We want to know what you think about the System, its future direction and performance as an investment and our communications with you.

Therefore, we urge you to complete and return the questionnaire attached to the back cover of this report. Your response will help us improve our shareholder relations and better serve you.

Initially, we mailed a pilot questionnaire to approximately 500 shareholders across the country. A number of shareholders were selected and interviewed based upon the geographic distribution of our shareholder base.

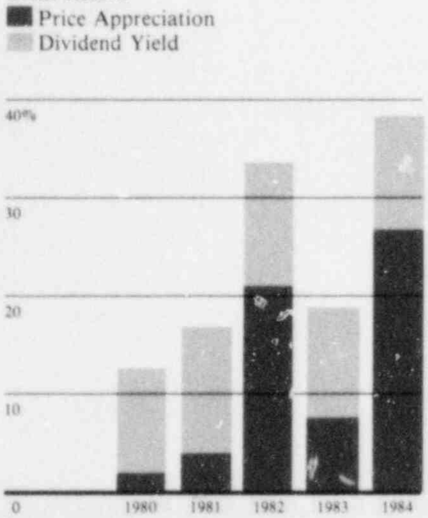
A vast majority of those interviewed felt that their investment in the System offers a good opportunity for capital appreciation and a reliable dividend return. Many also indicated that the Dividend Reinvestment Plan (DRP) is a very convenient way to increase their current investment in the System.

Your DRP dollars have provided a steady flow of capital and enabled us to forego public offerings of common shares since 1976 by raising approximately $25 million. We are projecting that an additional $37 million will be generated from DRP during the next five years. As long as adequate equity funding is available from this source, we do not foresee the need for a common share offering in the near future.

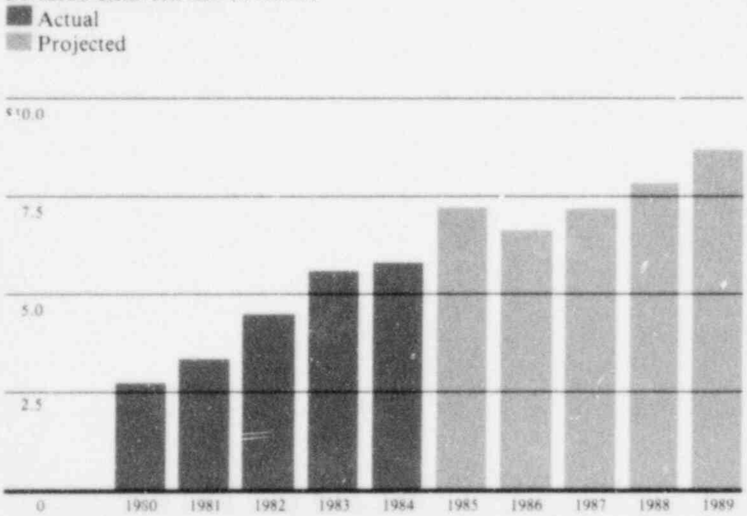
Your confidence in the System has not gone unrewarded. The price of a common share closed at $24½ in 1984 - up more than $5 from the $19¼ achieved in 1983, and considerably more than the $14¾ of 1980. In fact, you enjoyed a 38% total return during 1984 - 26½% in price appreciation and 11½% in dividend yield.

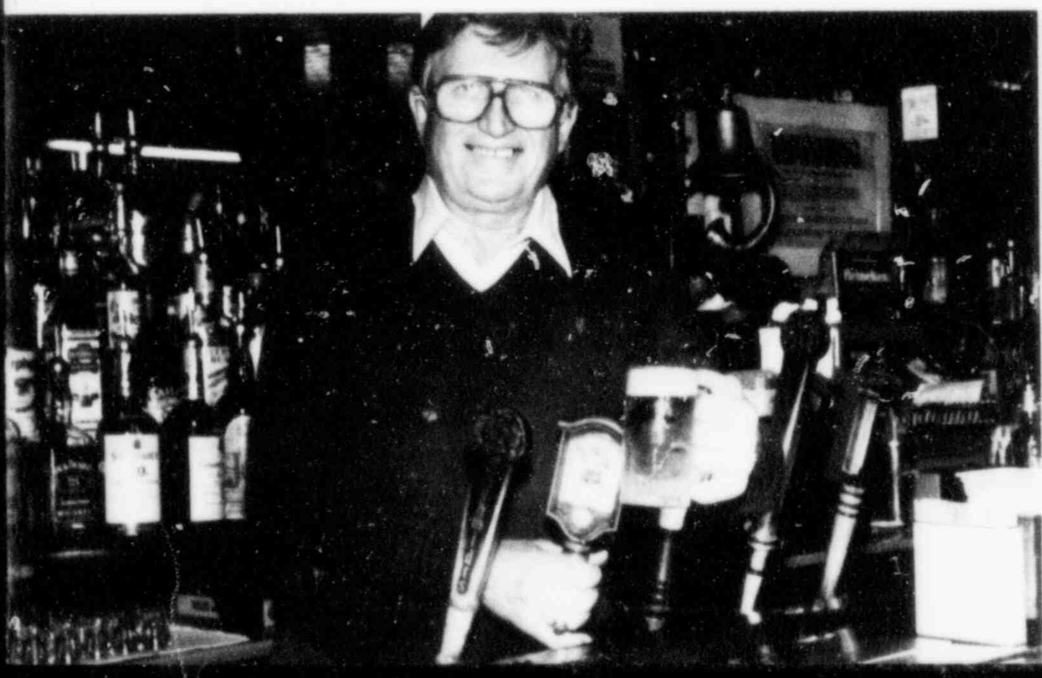
In addition to keeping you informed about the System's financial performance as well as current issues facing the System and the utility industry in general, it is also our goal to provide prompt responses to other informational requests you might have. Our latest effort in achieving this goal is the

Total Return



Dividend Reinvestment (in Millions)





1 Students and field hockey players at Dartmouth High School in Southeastern MA, Laurie, Susan and Jean Ryan received gifts of stock from their grandfather who wanted "...to provide a nest egg for our futures."

2 Spencer and Doris Yeich, both retired COM Energy employees now living in Sarasota, FL, acquired their shares "...as members of the Employees Savings Plan from the Plan's inception."

3 The owner and part-time proprietor of the Dugout Tavern in New York City, Emil Kovac sees COM Energy as "...a progressive, well-managed company, offering a good return on my investment."

implementation of improvements to our current shareholder information system. These improvements will provide us with the capability to respond to your questions on a more timely basis, generate a more extensive history of your account activity and establish an expanded data base from which we will be able to access a variety of statistical information. Your responses to the questionnaire on the inside back cover of this report will be extremely useful in enhancing this shareholder data base.

General Information

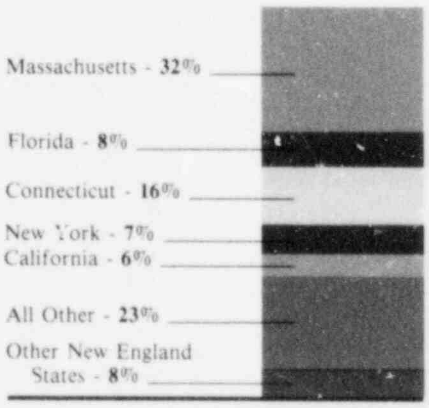
This "General Information" section is being provided in order to centralize certain information of interest to you as a shareholder. This information had been located in various sections of prior annual reports to you.

Executive Offices
Commonwealth Energy System
675 Massachusetts Avenue
Post Office Box 190
Cambridge, Massachusetts 02139
(617) 864-3100

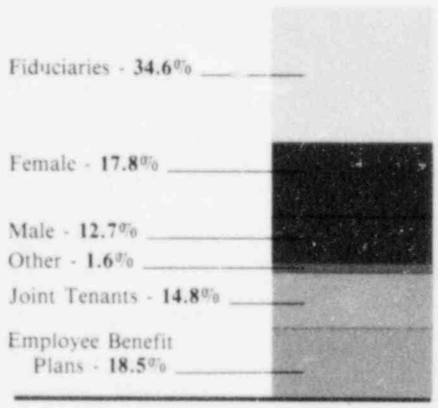
1985 Annual Meeting/Proxies
The Annual Meeting will be held at the executive offices of the System on Thursday, May 2, 1985 at 10:30 a.m. A formal notice of the meeting, a proxy statement and a proxy card will be mailed on or about April 1, 1985 to shareholders entitled to vote at the meeting.

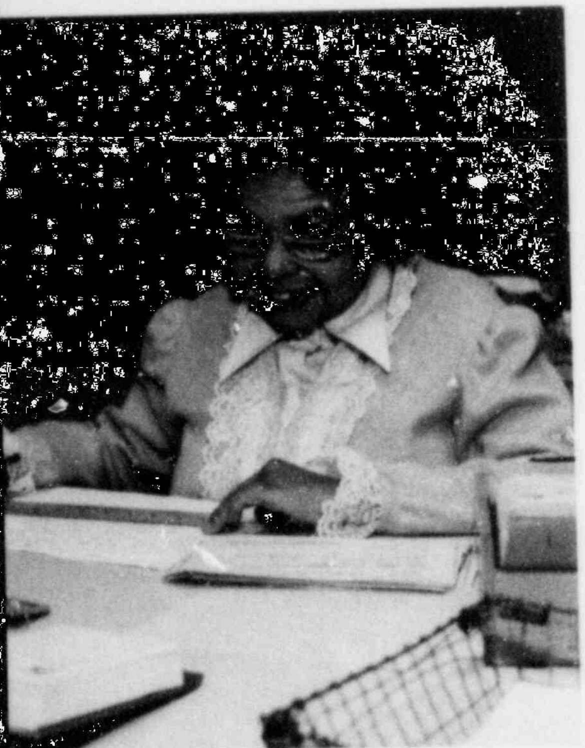
The proxy statement describes what issues will be voted on at the Annual Meeting, while the proxy card should be considered as the ballot on which you cast your vote on these issues by mail. Since our

Geographic Location of Shareholders



Shares Per Category





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shares are so widely distributed, it is imperative that you mail your proxy if you are not able to attend the Annual Meeting in order to ensure that a majority of common shares are represented at the meeting.

Common and Preferred Stock Listings

The Common Shares of the System are traded under the ticker symbol "CES" while the daily newspaper quotation is "ComES". The Common Shares are listed on the New York, Boston and Pacific Stock Exchanges.

The ticker symbol for Preferred Series D is "CES Pr D" while the newspaper quotation is "ComES pf". Preferred Series D is listed on the New York Stock Exchange. (Preferred Series A, B and C are not listed.)

Dividend Payments

Common and Preferred dividends are paid by the System upon declaration by the Board of Trustees. Common dividends are payable on the 1st day of February, May, August and November while preferred dividends are payable on the 1st day of January, April, July and October.

1 "I wanted stock that was secure, paid a good dividend and was located in Massachusetts so I could chart its progress," states Michael E. Brittain, 15, a resident of West Harwich, MA.

2 "...a Massachusetts-based company with a lengthy history of stability and growth" is the image Barbara Ann Thomas has of COM/Energy. Barbara lives and works as a clerk/stenographer in Boston, MA.

3 Retired financial vice president of COM/Energy, Burdette Johnson of Weston, MA considers investment in his own company "...a sound investment and an excellent way to save money, yielding a good annual income."

Transfer Agents and Registrars Common Shares

Transfer Agent and Registrar: The First National Bank of Boston
P. O. Box 644
Boston, MA 02102

Preferred Shares—Series A, B, C

Transfer Agent: Commonwealth Energy System
Registrar: State Street Bank and Trust Company
P. O. Box 5003
Boston, MA 02107

Preferred Shares—Series D

Co-Transfer Agents: Commonwealth Energy System and The First National Bank of Boston
Registrar: State Street Bank and Trust Company

Role of Transfer Agent

The transfer agent is primarily responsible for stock transfers requested by shareholders. If, for some reason, you wish to transfer your shares to another individual, you need to fill in the information on the back of your certificates and send it to the transfer agent at the above address. The transfer agent would then cancel the existing stock certificates and issue new certificates in the name of the person you have designated.

In the event your stock certificates are ever lost or stolen, contact the transfer agent immediately and provide the following information:

- the exact name in which the share certificates were issued
- the certificate numbers
- the number of shares
- the date of issuance

You should keep a record of the above information in a separate place for reference so that it is available if anything should happen to your certificates.

Duplicate Mailings
If more than one shareholder resides in your home and you do not wish to receive more than one copy of the Annual Report, we can restrict mailings to your address upon your written request.

Also, if you receive more than one dividend check or dividend reinvestment statement each quarter, it may be possible for you to combine your accounts if you so desire. Combining accounts would eliminate the inconvenience of receiving several dividend checks or dividend reinvestment statements and would reduce duplicate mailings. For information on the procedure for restricting mailings or combining accounts, please contact our System's shareholder services department.

Dividend Reinvestment Plan
The System offers you the opportunity to participate in its Dividend Reinvestment Plan by investing optional cash payments monthly and/or your quarterly dividends automatically in additional common shares. DRP participation has become an increasingly popular method for additional investment in the System.

One of the major attractions of qualified dividend reinvestment plans, such as ours, is the exclusion from taxable income of up to $750 (or $1,500 on a joint return) of qualified reinvested dividends through 1985. This exclusion, in general, does not apply to corporations, trusts, estates or nonresident aliens.

Other major features of our plan include:

- No brokerage fees: Participants do not pay any brokerage fees, transfer taxes or service charges.
- Optional cash payments: Participants may make optional cash payments in any month. These payments can be in varying amounts from as little as $10 per payment to a maximum of $5,000 per quarter. Payments are invested on the first day of the month following receipt.
- Record keeping and security: Simplified record keeping is provided through the issuance of a regular statement of account.

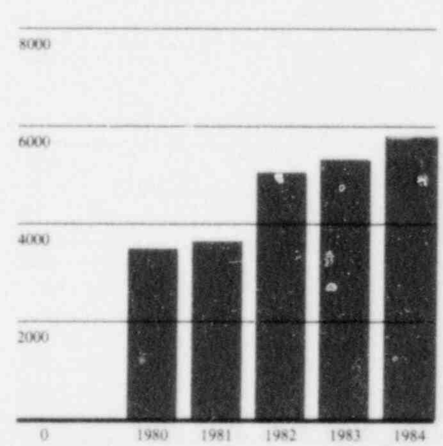
Enrollment in the plan is entirely voluntary and participants may withdraw at any time by written notice to the System.

Shareholder Awareness Program
Another step in our ongoing effort to provide improved service to you is the future development of a "Shareholder Awareness Program". The program's goal is to keep you aware of problems facing the System and the utility industry in general. As part of the program, we hope to set up several regional shareholder meetings, providing you with a forum to voice your opinion on the many critical issues facing the System today. In addition, we hope to provide tours of the System's more interesting facilities such as the Canal Electric Company's generating plant in Sandwich, MA.

If there are enough positive responses to the attached questionnaire, we will initiate this program as quickly as possible.

Additional information or questions about DRP, the Shareholder Questionnaire or the Shareholder Awareness Program can be obtained by writing to Commonwealth Energy System, Shareholder Services, P.O. Box 190, Cambridge, MA 02139.

Dividend Reinvestment
Number of Participants



1 Roy McCanne, head of the Education Department at the University of Southern Colorado at Pueblo, explains, "I'm holding COM/Energy stock as an investment for my future and the future needs of my family."

2 "I wish to see my initial investment appreciate, providing substantial dividends for our retirement," are the words of Harvey Leon Fisher, shown with his wife, Regina. Harvey is a warehouseman accountant from San Jose, CA.

3 A psychotherapist in private practice from New York City, Dorothy Jane Buzawa chooses to reinvest her dividends through participation in the Dividend Reinvestment Plan "...to build up equity and to defer taxes on the dividends."

Energy for a Growing Economy

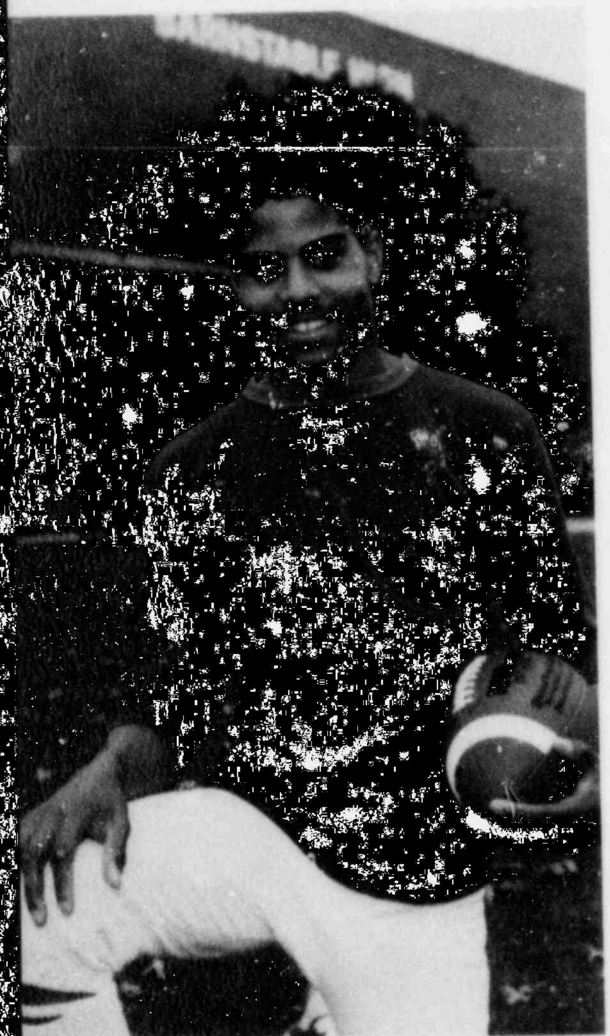
Driven by the strength of the Massachusetts economy, retail electric sales have grown by more than 6% during 1984, contributing to another strong year for the System. Peak electric load has also increased, reaching a record 719 megawatts on January 21, 1985. This growth, although encouraging, is accompanied by the challenge of securing sufficient capacity to support future economic growth. To help meet this challenge, the system has developed a strategy that integrates peak electric demand reductions with the acquisition of new conventional and alternative energy supplies.

Saving Energy Today and Reducing Future Costs

Working to reduce the electric demands of our customers may at first appear to be in conflict with the long-term investment objectives of our shareholders. But by promoting the efficient use of energy, the system is serving the interests of both customers and investors by reducing the average cost of electricity and enhancing the appeal of electricity as the power source of the future.

COM/Electric's "Saving Energy Together" campaign is helping customers minimize their energy costs in two ways. First, customers are realizing an immediate savings in their electric bills by taking advantage of one or more of the following programs:

- •Mass-Save Energy Audit
- •Mass-Save Electric Heat Rebate Program
- •Water-Heater Wrap and Weatherization Program
- •Low Income Weatherization Self-Help Kits
- •Commercial and Municipal Audit Program
- •Energy Information Program



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COM/Electric has conveyed the importance of efficient use of energy to all its customers, resulting in widespread customer interest and participation. More than 23,000 COM/Electric customers have received Mass-Save Energy Audits and approximately 12,000 customers have taken part in our weatherization programs. These conservation programs are saving over fifty million kilowatt-hours of electricity per year.

Secondly, COM/Electric is reducing customers' energy costs over the longer term through load management strategies. COM/Electric is promoting load management techniques by using interruptible and off-peak water heating rates and by improving the efficiency of electric transmission and distribution equipment. These combined efforts have cut peak electric load by more than 15 megawatts, delaying the system's need for new and expensive generating facilities.

Load management efforts have not stopped here. COM/Electric is one of only four electric utilities nationwide that is receiving funding from the Electric Power Research Institute for the testing and implementation of a Load Management Strategy Testing Model. This computerized model has been designed to simulate electric consumption patterns and the effects of load management during peak energy use. It also calculates the costs and savings of each load management alternative for direct comparison with investments in new generating capacity. The model thereby assists COM/Electric in choosing the least expensive approaches to meeting customer incremental energy needs.

1 William Finkel, a COM/Energy shareholder since 1977, has "faith in the company's ability to provide for energy needs." Bill is the owner of Captain Bill's Fish Market in Hyannis, MA.

2 Kip A. Diggs, a resident of Osterville, MA and a senior at Barnstable High School, said, "I became a stockholder when the shares were given to me by a very special man, my grandfather."

3 "My portfolio has a solid core of utility stock because I believe utilities are necessary to our country's welfare," says Mary Jefferies Harrar, a retired social worker from New York City.

Building on a Proven Power Base

Supplying approximately 50% of total system generation requirements in 1984, our Canal Electric generating facility continues to play an integral role in supplying electricity to our customers. As part of an ongoing program to maximize the plant's efficiency, we have installed a state-of-the-art computer to monitor the operation of Canal Unit 1. This new equipment has provided control room operators with timely information regarding the critical factors that influence the generation of electricity and has contributed to improved plant efficiency.

As one of only two large-scale electric generating plants under construction in New England, the Seabrook project holds special significance for system customers. Canal Electric's 3.52% ownership interest in the project will provide 40 megawatts of much-needed firm capacity from Unit 1 and will contribute to diversifying our energy base. In October 1984, Management Analysis Company, an independent consulting firm retained by the Seabrook joint-owners, issued a determination that the estimated cash-to-complete cost for Unit 1 was reasonable. Improvements in the project's management and procedures were cited as justification for their assessment. This evaluation reinforces our belief that Unit 1 can still be completed at a cost that is beneficial to our customers.

Tapping Every Available Energy Source

By aggressively seeking new conventional and alternate energy sources of electric energy throughout the Northeast region, we have strengthened our energy supply position. The SEMASS Project, a proposed "waste-to-energy" facility to be located in Rochester, MA, will be the largest supplier of alternately-produced energy to the system. The SEMASS facility will process up to 1,500 tons of refuse per day from participating communities and transform it into approximately 40 megawatts of electric capacity. In so doing, the plant will alleviate the serious solid waste disposal problem that exists in many of our communities while providing an important addition to our energy base.

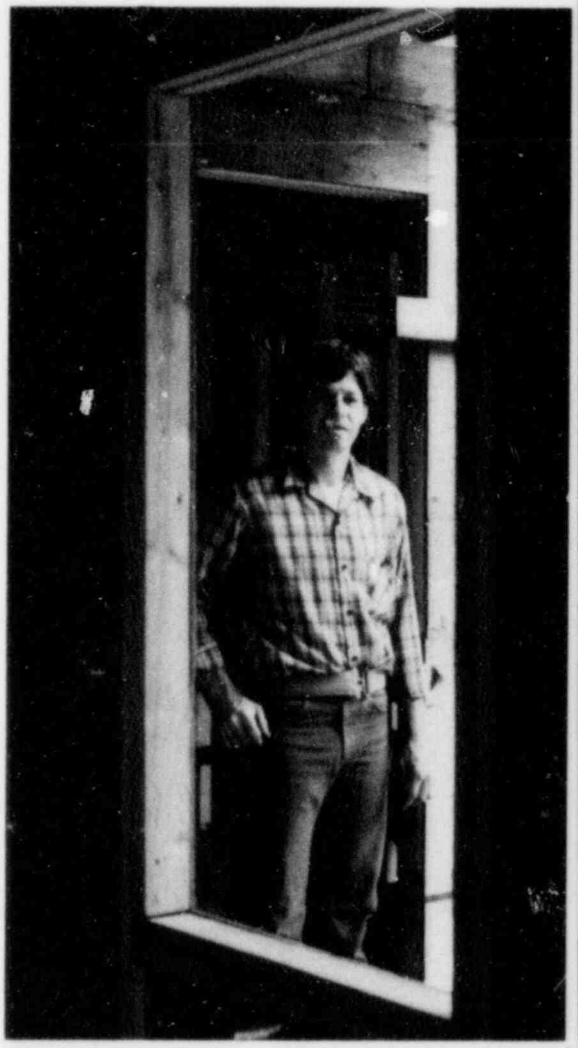
Energy Answers Corporation, the parent company of the SEMASS Project, has obtained $110 million in bond financing from the Industrial Bank of Japan. These proceeds are currently being held in an escrow account until all construction permits are obtained. With a two to three year construction lead-time, the plant could begin operation by 1988.

In order to contribute to the initial financial viability of the project, we will purchase power from the SEMASS facility at a cost which initially may exceed our avoided cost of energy. However, this cost will be continually reduced during the life of the contract until it reaches 70% of the avoided cost of energy in and after the seventeenth year of the contract. This should result in savings for our customers.

The Eldred L. Field Hydroelectric Project in Lowell, MA, under construction by Boott Hydropower, Inc., represents our largest new source of domestic hydroelectric supply. Powered by the Merrimack River, the $40 million facility will produce up to 23 megawatts of capacity and is expected to begin operation in September 1985. We will be purchasing all of the energy produced by this facility until 2023.

COM/Electric is also tapping other local alternative energy sources including seven small hydro plants and several windmills and is conducting research on a gas-expander turbine project. The combined electric capacity from these sources is almost 7 megawatts. In addition, we are participating in short-term energy sales and exchange contracts with other utilities to more effectively utilize existing electric capacity in the area.

While COM/Electric seeks to avoid excessive reliance on any foreign energy source, power purchases from Canada will complement our domestic generating capabilities. The construction of the Hydro-Quebec interchange is progressing and the flow of electricity to the New England states from the James Bay, Quebec facility is expected to begin in 1988. The Point Lepreau Unit 1



nuclear plant in New Brunswick has been supplying up to 25 megawatts of capacity to COM/Electric since July 1983, however, this source of power will only be available through 1991. COM/Electric has also submitted a letter of intent to obtain an additional 50 megawatts from the region should Point Lepreau Unit 2 be built. These power purchases, however, do not change our long-term objective of establishing a secure energy base in the New England region and we regard them only as a short-term solution in satisfying the need for energy for our growing economy.

Future Gas Supply Projects

Both of our pipeline suppliers, Algonquin Gas Transmission Company (Algonquin) and Tennessee Gas Transmission Company (Tennessee), have proposed major expansion projects which would make more gas available. Algonquin has already received permission from the Federal Energy

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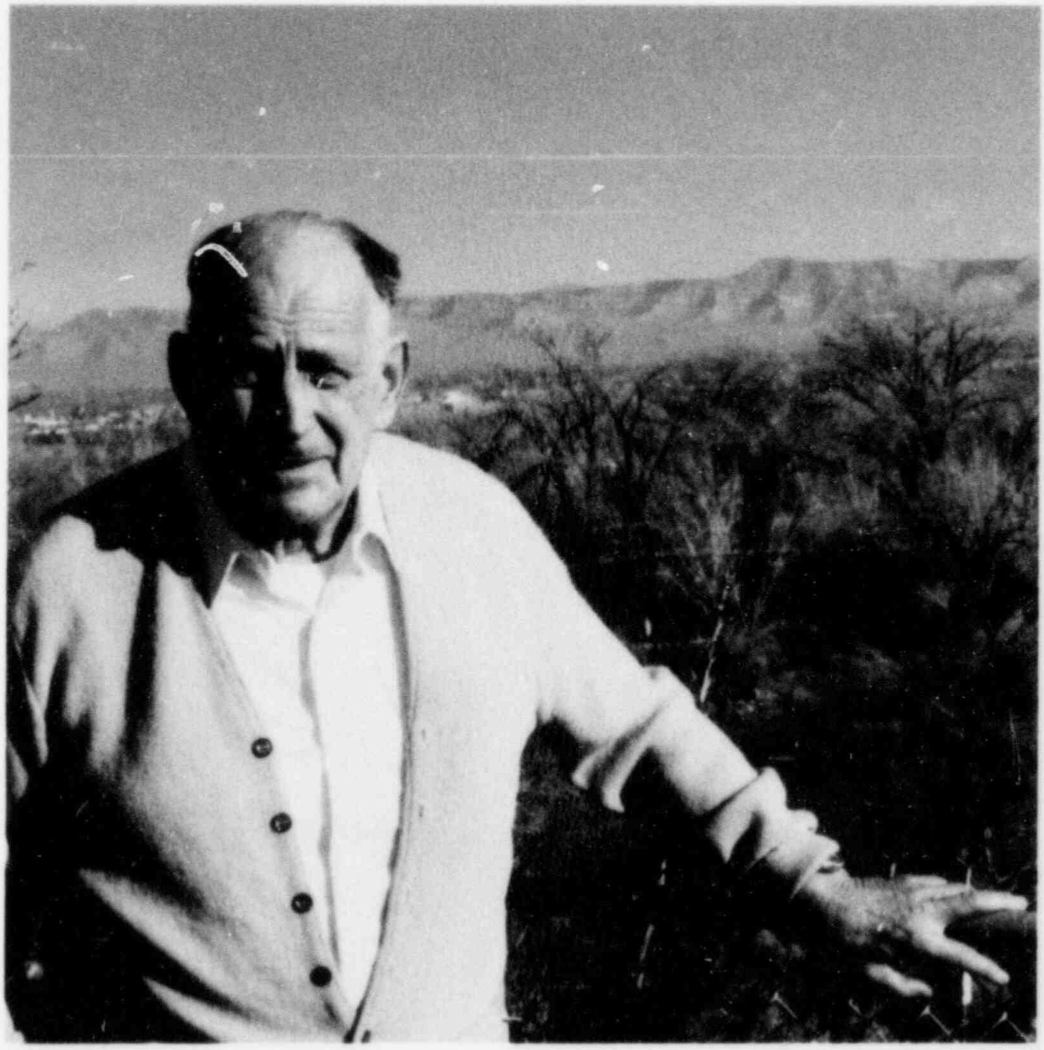
1 A small investor and a residential builder from Marstons Mills, MA, E. Richard O'Connell feels that "the ease of investing in the Dividend Reinvestment Plan meets my needs."

2 "What better gift for my daughter's birthday than a little security for her future," are the sentiments of John "Tim" Higgins of West Yarmouth, MA, a general excavation contractor and the custodian of Stormy Dae Patrick's shares.

3 "The stock's financial rating is A. Earnings and dividends, per share, have had a consistent growth pattern. The price of the stock has not had wild fluctuations. Management has kept us well informed on its future prospects and problems. Based on these facts, why would we sell?" John and Dorothy Backstrand, Retired, Riverside, CA.

Regulatory Commission (FERC) to construct the CONTEAL Project. This project will provide COM/Gas with up to 12,000 MCF/day of gas on a firm basis beginning November 1, 1986. Algonquin and its major supplier, Texas Eastern Transmission Company, recently filed an application for another major system expansion project. If this project is approved by FERC, COM/Gas would purchase approximately 8,000 MCF/day of gas on a firm basis beginning November 1, 1985 and up to 15,000 MCF/day beginning November 1, 1986. These two major Algonquin supply projects will allow us to replace high-cost SNG with lower-cost pipeline gas once the SNG contract expires. These projects would also provide capacity for future load growth.

Tennessee has also proposed a system expansion which would allow us to convert the current best-efforts storage transportation agreement to a firm supply allowing us to increase our maximum daily quantity by approximately 7,000 MCF/day. This agreement would also allow COM/Gas to use Tennessee storage gas to meet peak day requirements. Both the storage agreement and the daily contract expansion would provide capacity for future growth and strengthen our supply system. The storage project is tentatively scheduled for November 1, 1985 while the contract expansion is tentatively scheduled for November 1, 1987.



This expansion by both Algonquin and Tennessee represents a response to the recent changes that have occurred nationally affecting the gas industry. Pipeline customers in other parts of the country, particularly the Midwest, have sought to reduce their contract levels due to a shift in gas demand. Through a series of complex negotiations and pipeline construction projects, these volumes of gas will be made available to growing gas markets in the Northeast.

Hopkinton LNG Corp.

In January 1985, the System became sole owner of Hopkinton LNG Corp. (Hopkinton) by purchasing Air Products and Chemicals' 50% ownership interest at a cost of $2.5 million.

Hopkinton owns liquefaction and vaporization facilities in Massachusetts which have the

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capacity to supply full gas service to approximately 26,000 homes for a full year.

During the non-heating season of April 5 to November 15 of each year, COM/Gas furnishes pipeline gas which Hopkinton liquefies and stores at its facilities. As the need arises, the gas is vaporized and placed in the distribution system of COM/Gas. This service provides substantial savings to our customers by avoiding the higher cost of other types of supplemental gas supplies.

Future Gas Marketing Potential

Consistent with our greatly improved gas supply picture and the competitive advantage of gas prices, we will continue our aggressive marketing posture. We are presently promoting the use of co-generation facilities among our industrial and commercial customers, specifically large and mid-sized industrial and health-care facilities. Fortunately, COM/Gas is in the enviable position of serving an area that is enjoying economic growth and a large amount of new construction. Our employees are actively involved, giving presentations to various architects, design engineers and property developers/owners, introducing them to the potential benefits of innovative gas space heating systems, a new generation of highly efficient gas-absorption air-conditioning equipment and co-generation.

Gas air conditioning is presently enjoying a revival of interest with the recent introduction of a wide range of systems to the market. Users of these systems enjoy the efficiency and economic benefits of cooling with natural gas. These systems, aimed specifically at the commercial/institutional user, have the advantage of providing a firm source of natural gas sales during the summer months, traditionally a period of reduced consumption.

Co-generation is an integrated energy system that uses an engine powered by natural gas to produce both usable heat and electric energy. These energy forms will help to meet the customer's heating and electricity requirements. The customer can sell electricity to local utilities when an excess is generated or purchase it if the system does not generate enough to meet its needs.

Feasibility studies are presently being conducted on several industrial and commercial users having an aggregate potential consumption of more than 1,200,000 MCF of firm gas per year.

1 Howard Hottes, a retired engineer from Grand Junction, CO and a shareholder since 1957 says, "COM/Energy stock is a sound investment I have only recently recognized."

2 Jean M. Snow, a stockholder enrolled in the Dividend Reinvestment Plan and an account executive with Thomson McKinnon, Inc., Osterville, MA, believes the management of COM/Energy to be "the best in the utility industry."

3 Ismaele D'Alleva, owner of the Garden Fresh Company of Chelsea, MA and a stockholder since 1983, thinks "utilities will prosper because they have contributed to the standard of living Americans have become used to."

A recent market survey conducted on the health-care sector also shows great promise. COM/Gas currently serves 31 hospitals, all of which are excellent candidates for co-generation. These facilities collectively represent potential firm gas sales of 975,000 MCF per year. Nursing homes also represent a significant potential source of firm sales through the use of smaller modular systems. In general, the health-care market, under pressure to reduce costs, should be very receptive to the concept of co-generation. Overcoming the cost of the initial investment is achievable with the advent of third-party financing arrangements.

The market is continually expanding with the emergence of a whole new sector of the co-generation market in previously non-feasible installations. Reduced capital equipment costs and the increased availability of reliable co-generation modular units in the 15 to 60 kilowatt range is providing the impetus for consumers to reduce energy costs. Future gas sales to co-generation facilities could prove to be substantial.

Gas Facilities Management Through Computer Graphics

COM/Gas is developing an automated mapping and facilities management system designed to consolidate multiple records and map sets into one central filing system. When fully implemented this system will provide management, engineers and construction crews with graphic and tabular information on the precise location, size, condition, maintenance history and costs of mains, services and other related equipment. This information will replace a number of record systems resulting in a significant cost savings. Records and maps presently in use will be compiled and stored in a comprehensive data base and displayed on graphic work station terminals. Reproduction of these displays can be made in hard copy format. Ultimately, this system will have the capability of displaying concise gas distribution data on any city or town, street or dwelling in the COM/Gas service territory.

Several major tasks are currently in progress to develop the land-base segment of this system. Aerial photographs of the 30 square-mile area encompassing the towns of Natick and Framingham have been entered into a data base. This data then interacts with the graphics software to display such information as the exact location of buildings, roadways and utility structures. Photographs of the 400 square mile area, extending from the Town of Dedham west to the City of Worcester, have also been completed. In addition to development of this land base, COM/Gas personnel are preparing existing records for the conversion process which will lead to full implementation by 1990.

When fully operational, this system will improve the accuracy and reliability of records in a manner which is manageable, easily used and cost effective. This project represents a significant step taking COM/Gas into the future, a future that requires the most current technology to be a competitive leader in the energy industry.

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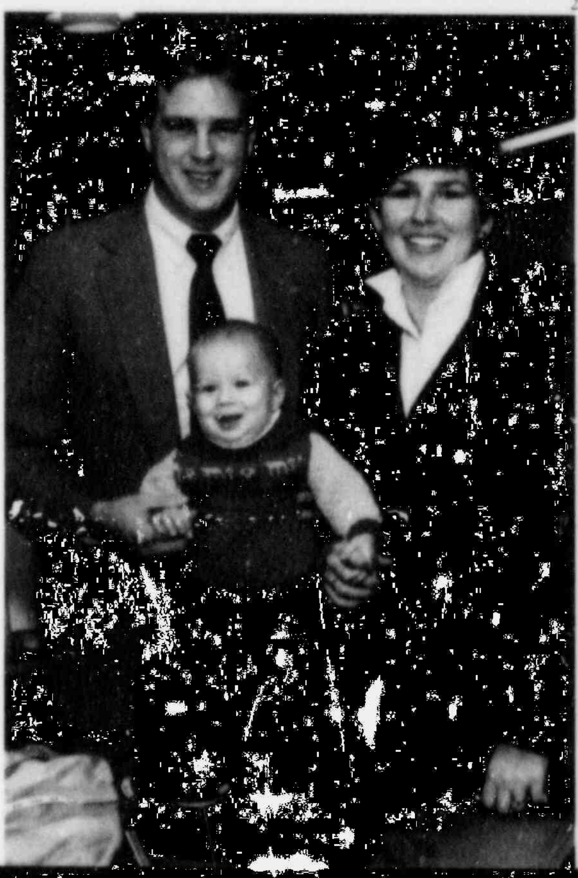

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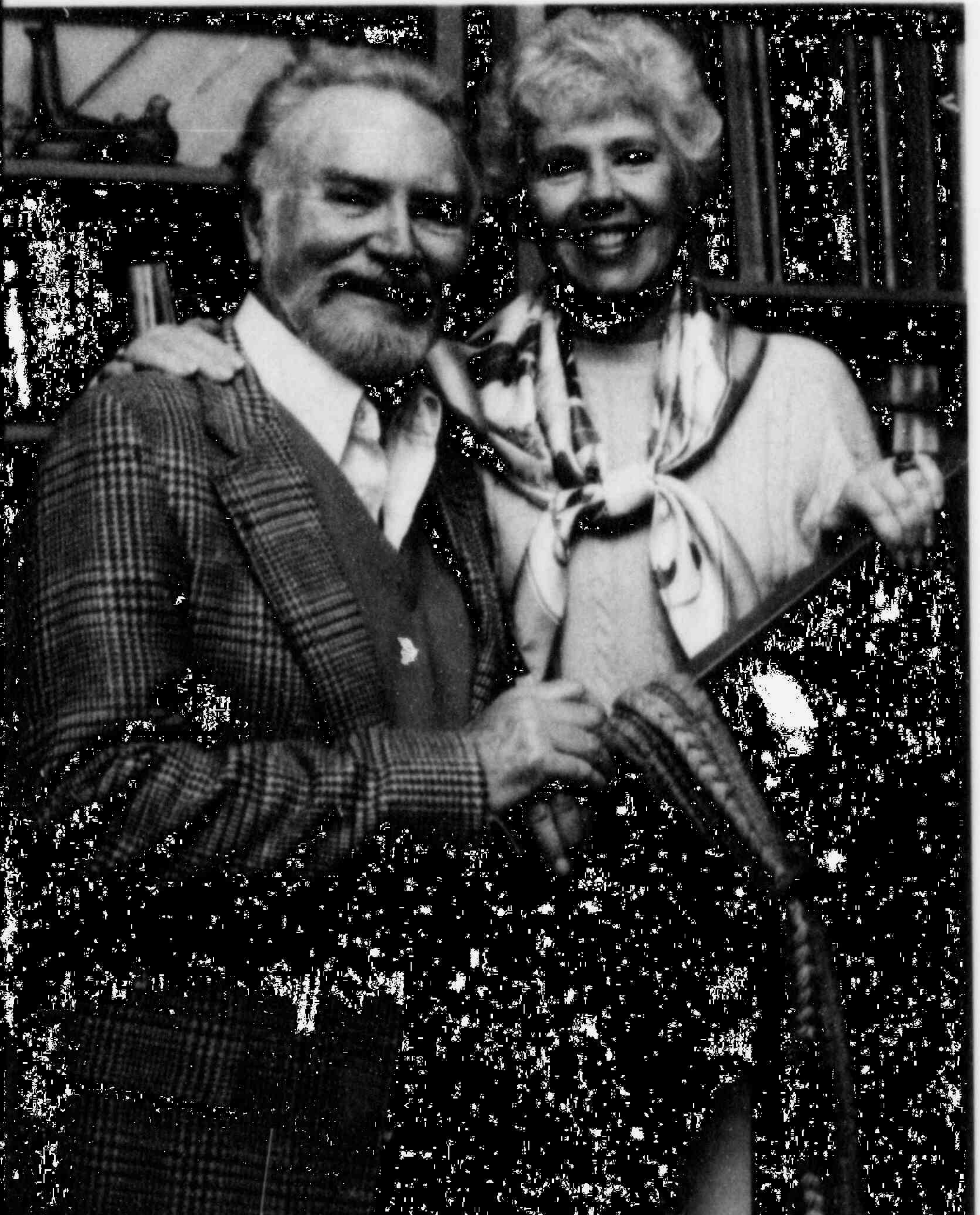

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1 Elizabeth Connors inherited her shares in 1962. For sentimental reasons, Betty holds onto the stock and hopes "...to see dividends improve even more in the future." Betty and her husband, John, are retired and live in Sarasota, FL.

2 Andrew and Joan Witter, owners and operators of two specialty stores for women on Cape Cod, MA, have concerns for their energy future and their son Devin's security in that future. "The Dividend Reinvestment Plan helps us ease both those concerns."

3 "It was my opinion that the weather in the East, the growth of population, and revitalization of industries in the COM/Energy service area would result in stable and increasing dividends. Fortunately, this has proven true." Leonard Salvo, a school-district supervisor and his wife, Nancy, of Glendora, CA.

Real Estate Activities

The first phase of the Riverfront Office Park Project, an eighteen-story office tower of 330,000 square feet located in Kendall Square, Cambridge, MA, is 92% leased and occupied. We have an impressive roster of tenants including The Saddlebrook Corporation, IBM, AT & T, Bay State Health Care, SEI Corporation, Trammell Crow, Bankers Leasing and Regis McKenna. Phase One is built on land owned by our Darvel Realty Trust and leased to a joint venture consisting of JMB Realty of Chicago, Illinois, and a partnership consisting of Darvel Realty Trust, Macomber Development Associates and The Codman Company.

The second phase of the Riverfront Office Park Project will consist of a fourteen-story office tower of 325,000 square feet and a four-story parking garage connecting to the first phase. This phase is also on land owned by Darvel Realty Trust and will be leased to a partnership formed with Darvel Realty Trust, Macomber Development Associates and The Codman Company. The lead tenant in the building will be our COM/Energy Services Company which will occupy the top five floors and most of the ground level. The building will be named The COM/Energy Building.

During 1984, our COM/Energy Cambridge Realty and COM/Energy Realty Trust sold the two buildings where the Services Company offices are now located and arranged a leaseback until the new headquarters building is constructed. Consolidation of our space will substantially improve our operational efficiency.

Ground-breaking is scheduled for early 1985, with completion and occupancy scheduled for early 1987.

Changes in the Board of Trustees

John F. Rich has announced his intention not to seek re-election to the Board of Trustees. Mr. Rich joined the Board in 1947 and during his thirty-eight year tenure has served as President, Chief Executive Officer and Chairman of the Board.

Also leaving the Board are George P. Wadsworth, who is ending thirty-eight years of service to the System, and Thomas H. Bilodeau, a Trustee for 17 years.

We are forever grateful to these men. Their counsel, leadership, dedication, and direction have been instrumental to the growth, continued development and success of the System.

Mr. Bilodeau's retirement, effective December 31, 1984, led to the nomination and election of Mr. Franklin M. Hundley to fill this vacancy. Mr. Hundley is a partner in the law firm of May, Bilodeau, Dondis & Landergan.

Two individuals have been proposed as nominees to fill the other vacant positions. One is Mr. Henry Dormitzer, Vice President—General Manager, Aerospace Group of Wyman-Gordon Company and the other is Gerald L. Wilson, Dean of the School of Engineering of Massachusetts Institute of Technology.

Financial Section

Commonwealth Energy and Subsidiary Companies

Contents

Management's Report

The financial statements presented herein are representations of the management of Commonwealth Energy System. Management recognizes its responsibility for the preparation and presentation of financial statements in conformity with generally accepted accounting principles. To fulfill this responsibility, management maintains a system of internal accounting controls including established policies and procedures and a comprehensive internal auditing program to evaluate the adequacy and effectiveness of accounting and operating controls, compliance with system policies and procedures and the safeguarding of system assets.

The responsibility of our independent auditors' examination is limited to the expression of an opinion as to the fairness of the financial statements presented. The independent auditors are selected by the Board of Trustees and report their findings thereto through the Audit Committee, which is comprised of three outside Trustees. The Board of Trustees is responsible for ensuring that both the independent auditors and management fulfill their respective responsibilities as they pertain to these financial statements.

E. G. Cheney,
Financial Vice President

February 22, 1985.

Management Discussion and Analysis of Financial Condition and Results of Operations

Regulation

The System's operating subsidiaries are subject to the jurisdiction of state and Federal regulatory agencies with respect to the establishment of rates affecting retail electric and gas sales and wholesale electric sales.

The Massachusetts Department of Public Utilities (DPU) requires historic test-year information to support changes in rates; however, it has become more progressive in other rate-making practices. In 1982, the DPU allowed our system retail utilities to include known and measurable changes in cost of service and rate base calculations and granted inflation allowances as well as higher returns on common equity. These equity returns range from 15% to 15.5% on capital structures with equity components of slightly more than 50%.

At the wholesale level, the Federal Energy Regulatory Commission (FERC) had allowed Canal Electric, effective January 9, 1984, to include one-half of its Construction Work In Progress in rate base, subject to refund, pending further regulatory hearings. After more than one year, the FERC staff and the Massachusetts' Attorney General sought additional discovery requests which were so extensive and far-reaching in scope that we determined that, from a cost-benefit standpoint, it was not in Canal Electric's best interests to pursue the issue.

In another matter, Canal Electric has filed testimony and additional data with the DPU relating to justification of its continued participation in the Seabrook Unit 1 nuclear generating facility. We expect that the hearings on this issue will be concluded in early April and the DPU will render a decision soon thereafter. This decision will determine whether Canal Electric's proposed financing of $20 million of long-term debt, $25 million of common stock and a $12 million nuclear fuel lease will be completed.

Results of Operations

Operating revenues for 1984 increased by nearly $104 million or 16.8% over 1983 due to a substantial increase in electric KWH sales, particularly wholesale which rose 83.2% as a result of a more normal operating year in 1984 as compared to 1983 when we experienced an extended outage at our Canal generating facility. Increases in the cost of fuel and purchased power also contributed to the change in operating revenues. Gas MCF sales, including interruptible, rose by 5% during 1984; however, revenues relating to these sales declined primarily due to the lower cost of gas. Although residential sales to both gas and electric customers were the primary contributors to our much-improved sales performance, commercial and industrial sales also played a significant role, reflecting robust economic conditions in the region. Fluctuations in the level of wholesale electric and interruptible gas sales have little, if any, impact on net income.

The full impact of the rate relief granted to the System's retail subsidiaries coupled with the 5.9% increase in retail electric KWH sales was responsible for the increase in revenues in 1983 while the 1982 change was primarily the net result of changes in the cost of gas, fuel and purchased power.

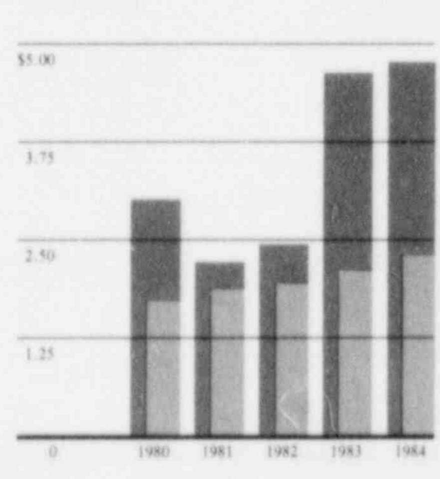
During the three-year period, 1982 through 1984, the per MCF cost of gas averaged $4.78, $4.81 and $4.52, respectively, while fuel and purchased power costs per KWH were 4.3¢, 4.4¢ and 5.0¢. The significant decline in the cost of gas during 1984 was due to a much-improved gas supply situation. Fuel and purchased power costs were considerably higher in 1984 because of the unavailability of traditionally lower-cost nuclear power due to extended maintenance at several units and an increase in oil prices at our Canal generating facility which averaged $28.56 per barrel in 1984 compared to $26.13 last year.

In general, other operating and maintenance costs have risen throughout the three-year period reflecting inflationary pressures on material, labor and other services. Property taxes have dropped during the same period because of lower property tax rates and valuations in a number of the cities and towns in our service area.

Other income was up in 1984 by $1.3 million or 9.3% after increasing by $5.8 million or 67.7% in 1983. The higher level of other income in 1984 was due to recognition of $4.3 million of a total after-tax gain of $6.1 million relating to the sale of our corporate headquarters office complex. The increase in other income in 1983 reflected $2.2 million of interest income associated with uncollected deferred gas costs and a $1.3 million

Earnings and Dividends

Earnings
Dividends



increase in the allowance for equity funds used during construction. In 1984, these two items amounted to $732,000 and $258,000, respectively.

Total interest charges have declined during the year as a result of a 36% increase in the allowance for borrowed funds used during construction and lower short-term interest charges caused by a decline in bank borrowings during 1984. Offsetting the effect of these two items was higher long-term interest expense, reflecting the full impact of $23.3 million of long-term debt issued in December 1983.

Capital Resources

Interim and permanent financing is done on an individual company basis. The System purchases 100% of all subsidiary common stock issues and provides, to the extent possible, a portion of the subsidiaries' short-term financing needs. The System's principal sources of capital are its retained earnings and the equity funds provided through its Dividend Reinvestment and Common Share Purchase Plan (DRP). However, these sources are supplemented, when necessary, with new equity and/or debt issues.

Subsidiary companies also participate in the COM/Energy Money Pool (the Pool). This is an arrangement whereby any subsidiary companies' 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 those offered by banks.

System companies also maintain lines of credit with banks. At December 31, 1984, short-term notes payable to banks were $53.4 million, down $8.1 million from last year.

Liquidity

The system is able to generate an adequate level of cash to meet its needs through the collection of accounts receivable generated from the sale of electric, gas and steam to retail and wholesale customers. Other cash sources include rental income, dividends from investments, the sale of common shares through DRP and periodic short-term borrowings from banks.

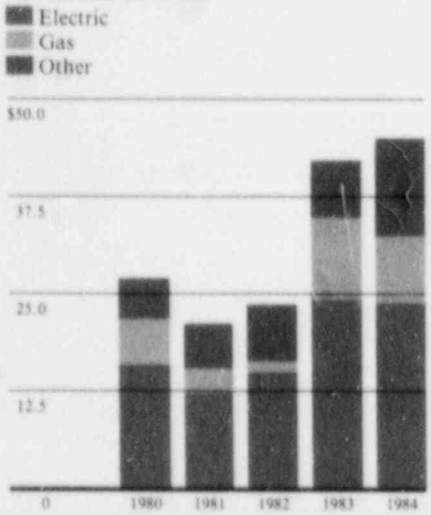
Construction expenditures for 1984 were approximately $58.6 million, including allowance for funds used during construction and nuclear fuel. Of this amount, approximately $26.6 million relates to our participation in the Seabrook project.

Over the next five years, we are projecting the following total system capital requirements:

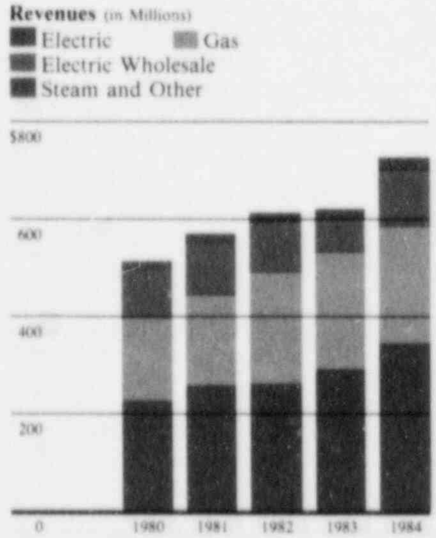
•Construction expenditures	$327,831,000
•Maturing long-term debt	80,284,000
•Sinking funds	27,985,000
	$436,100,000

Although Seabrook is still our largest single project, it is no longer as dominant in our total construction program due to the abandonment of the second unit (see Note 3). By the end of 1989, our financing program calls for reducing total short-term debt to less than $15 million thereby requiring the System's operating subsidiaries to issue approximately $172 million in new long-term debt and $94.5 million in new equity capital. During the period, we anticipate generating almost $280 million of our capital requirements internally.

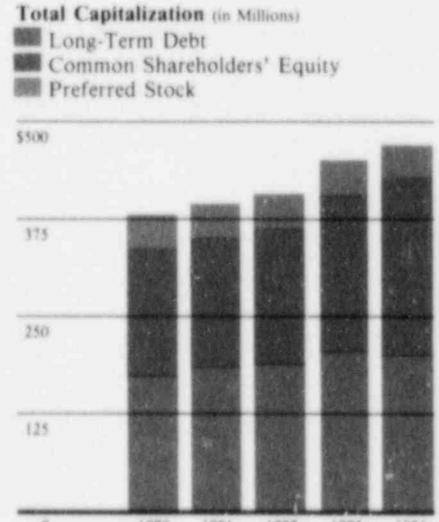
Net Income (in Millions)



Revenues (in Millions)



Total Capitalization (in Millions)



Report of Independent Public Accountants

To the Board of Trustees of Commonwealth Energy System:

We have examined the consolidated balance sheets and statements of capitalization of COMMONWEALTH ENERGY SYSTEM (a Massachusetts trust) and subsidiary companies as of December 31, 1984 and 1983, and the consolidated statements of income, changes in common shareholders' investment, changes in redeemable preferred shares and sources of funds used for construction, for each of the three years in the period ended December 31, 1984. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances. We did not examine the consolidated financial statements of Algonquin Energy, Inc., the investment in which is reflected in the accompanying financial statements using the equity method of accounting. The consolidated financial statements of Algonquin were examined by other auditors whose report has been furnished to us, and our opinion expressed herein, insofar as it relates to amounts reported by Algonquin, is based solely upon the report of the other auditors.

As more fully discussed in Note 3, the System has ownership interests in Unit 1 and Unit 2 of the Seabrook Project. The System has abandoned its investment in Unit 2 and intends to seek regulatory approval for full recovery of its investment in that unit in 1985. There are significant uncertainties with regard to the completion and commercial operation of Unit 1. In the event that Unit 1 is not completed, recovery of the System's investment in that Unit would also be dependent upon regulatory approval. It is not possible to predict what portion, if any, of the System's investments in these units may not be recovered.

In our opinion, based upon our examination and the report of other auditors and subject to the effects on the 1984 financial statements of such adjustments, if any, as might have been required if the outcome were now known of the uncertainties referred to in the preceding paragraph, the financial statements referred to above present fairly the financial position of the System and subsidiary companies as of December 31, 1984 and 1983, and the results of their operations and their sources of funds used for construction, for each of the three years in the period ended December 31, 1984, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Boston, Massachusetts,
February 22, 1985.

Consolidated Statements of Income

Commonwealth Energy System and Subsidiary Companies

Years Ended December 31,	1984	1983	1982
		(Dollars in Thousands)	
Operating Revenues:			
Electric	**$465,891**	$356,895	$361,908
Gas	**242,617**	246,224	231,003
Steam and other	**15,139**	16,536	14,170
	723,647	619,655	607,081
Operating Expenses:			
Fuel used in electric production, principally oil	**223,719**	160,571	198,610
Electricity purchased for resale	**80,780**	45,939	26,217
Cost of gas sold	**168,777**	171,034	173,493
Other operation	**110,494**	102,339	93,249
Maintenance	**28,899**	25,780	26,371
Depreciation	**20,586**	19,846	18,936
Taxes—			
Local property	**12,086**	14,628	17,575
Income (Note 4)	**29,144**	30,709	15,787
Payroll and other	**5,707**	5,036	4,769
	680,192	575,882	575,007
Operating Income	**43,455**	43,773	32,074
Other Income (Expense):			
Equity in earnings of Algonquin Energy, Inc. (Note 2)	**6,090**	5,860	5,839
Allowance for equity funds used during construction	**3,930**	3,672	2,349
Sale of buildings, net (Note 9)	**4,340**	—	—
Abandoned nuclear projects, net	—	—	(1,472)
Other, net	**1,229**	4,730	1,788
	15,589	14,262	8,504
Income Before Interest Charges	**59,044**	58,035	40,578
Interest Charges:			
Long-term debt	**17,693**	15,154	16,088
Other interest charges	**6,114**	7,310	7,576
Allowance for borrowed funds used during construction	**(9,731)**	(7,157)	(6,683)
	14,076	15,307	16,981
Net Income	**44,968**	42,728	23,597
Dividends on preferred shares	**3,423**	3,601	3,734
Earnings Applicable to Common Shares	**$ 41,545**	$ 39,127	$ 19,863
Weighted Average Number of Common Shares Outstanding	**8,747,626**	8,451,316	8,103,922
Earnings Per Common Share	**$4.75**	$4.63	$2.45

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

Consolidated Balance Sheets

Commonwealth Energy System and Subsidiary Companies

December 31,	1984	1983
	(Dollars in Thousands)	
Assets		
Property, Plant and Equipment, at original cost:		
Electric	**$452,796**	$436,114
Gas	**154,359**	144,295
Other	**15,305**	22,086
	622,460	602,495
Less—Accumulated depreciation	**216,514**	202,265
Accumulated deferred income taxes	**75,507**	70,732
	330,439	329,498
Construction work in progress, net (Notes 3 and 4)	**119,250**	115,543
	449,689	445,041
Leased Property, net (Note 10)	**10,522**	8,476
Equity in Corporate Joint Ventures:		
Algonquin Energy, Inc. (34.5%)	**44,842**	42,912
Nuclear electric power companies (2.5% to 4.5%)	**9,020**	8,991
Hopkinton LNG Corp. (50%) (Note 1)	**1,463**	1,658
Other investments	**2,087**	2,264
	57,412	55,825
Current Assets:		
Cash	**5,115**	21,219
Accounts receivable, less reserves of $3,014,000 in 1984, and $2,930,000 in 1983	**68,773**	60,386
Unbilled revenues	**32,428**	31,460
Inventories, at average cost—		
Electric production fuel oil	**6,504**	5,146
Natural gas	**18,068**	16,089
Materials and supplies	**5,731**	5,439
Prepaid property taxes	**6,477**	6,904
Other	**7,486**	5,505
	150,582	152,148
Deferred Charges, net (Notes 3 and 4)	**18,976**	6,922
	$687,181	$668,412

December 31,	1984	1983
	(Dollars in Thousands)	
Capitalization and Liabilities		
Capitalization (See separate statement):		
Common share investment	**$230,434**	$202,713
Redeemable preferred shares, less current sinking fund requirements	**38,560**	40,380
Long-term debt, less current sinking fund requirements and maturities	**200,721**	206,303
	469,715	449,396
Capital Lease Obligations - (Note 10)	**7,806**	6,491
Current Liabilities:		
Interim Financing—		
Notes payable to banks (Note 7)	**53,400**	61,500
Maturing long-term debt	—	169
	53,400	61,669
Other Current Liabilities—		
Current sinking fund requirements	**4,290**	4,137
Accounts payable	**65,985**	59,783
Accrued taxes—		
Local property and other	**7,296**	10,469
Income	**8,427**	15,594
Accrued interest	**3,605**	3,867
Dividends declared	**6,005**	5,437
Capital lease obligations (Note 10)	**2,716**	1,985
Other	**15,382**	13,771
	167,106	176,712
Deferred Credits:		
Unamortized investment tax credits	**32,597**	31,199
Other	**9,957**	4,614
	42,554	35,813
Commitments and Contingencies (Note 3)		
	$687,181	$668,412

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

Consolidated Statements of Sources of Funds Used for Construction

Commonwealth Energy System and Subsidiary Companies

Years Ended December 31,	1984	1983	1982
		(Dollars in Thousands)	
Sources of Funds—			
Internal Sources			
From Operations—			
Net Income	**$44,968**	$42,728	$23,597
Items not requiring or (providing) funds:			
Depreciation and amortization	**22,345**	23,120	20,709
Deferred income taxes—long-term	**16,000**	6,568	6,063
Investment tax credits, net	**1,398**	3,736	4,230
Equity in earnings of joint ventures, reduced by cash dividends of $5,940,000 in 1984, $4,940,000 in 1983 and $2,928,000 in 1982	**(1,764)**	(2,477)	(4,175)
Allowance for equity funds used during construction	**(3,930)**	(3,672)	(2,349)
Abandoned nuclear projects, net	**—**	—	1,472
	79,017	70,003	49,547
Less—			
Payment of dividends	**23,355**	20,915	19,189
Retirement of long-term debt and preferred shares through sinking funds	**5,285**	5,022	5,488
Other	**(8,302)**	(1,540)	(3,646)
	20,338	24,397	21,031
Change in net current assets (exclusive of interim financing)—			
Cash	**16,104**	(17,633)	(1,684)
Accounts receivable and unbilled revenues	**(9,355)**	1,784	(8,874)
Local property and other taxes	**(2,746)**	2,633	(5,211)
Accrued income taxes	**(7,167)**	7,798	(2,814)
Accounts payable and other	**3,393**	16,250	(20,996)
	229	10,832	(39,579)
Net available from internal sources	**58,908**	56,438	(11,063)
External Sources			
Sale of common shares	**6,108**	6,272	5,480
Notes payable to banks, net	**(8,100)**	(28,600)	64,100
Long-term debt issues	**—**	23,300	6,000
Long-term debt issues refunded	**(2,286)**	—	(6,091)
Net available from external sources	**(4,278)**	972	69,489
	$54,630	$57,410	$58,426
Funds Used for Construction—			
Electric	**$46,713**	$52,396	$51,428
Gas	**11,479**	7,508	7,558
Other	**368**	1,178	1,789
	58,560	61,082	60,775
Less—Allowance for equity funds used during construction	**3,930**	3,672	2,349
	$54,630	$57,410	$58,426

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

Consolidated Statements of Capitalization

Commonwealth Energy System and Subsidiary Companies

December 31,	1984	1983
	(Dollars in Thousands)	
Common Share Investment:		
Common shares, $4 par value—		
Authorized—12,000,000 shares		
Outstanding—8,904,086 in 1984 and 8,596,802 in 1983	**$ 35,616**	$ 34,387
Amounts paid in excess of par value	**53,056**	48,177
Retained earnings (Note 6)	**141,762**	120,149
Total common share investment	**230,434**	202,713
Redeemable Preferred Shares, Cumulative, $100 par value (Note 5):		
Series A, 4.80%	**4,080**	4,200
Series B, 8.10%	**6,080**	6,240
Series C, 7.75%	**14,220**	14,760
Series D, 9.80%	**16,000**	17,000
Less current sinking fund requirements	**(1,820)**	(1,820)
Total redeemable preferred shares	**38,560**	40,380
Long-Term Debt, including premiums (Note 7):		
System Bonds, collateralized by common stock of utility operating subsidiaries, due—		
1987, 6⅜%	**13,066**	13,224
1988, 6⅞%	**2,879**	2,964
1996, 8⅞%	**3,657**	3,757
1999, 4.80%	**2,880**	3,060
Less current sinking fund requirements	**(521)**	(521)
Total System long-term debt	**21,961**	22,484
Subsidiary companies' long-term debt		
Mortgage Bonds due—		
1992, 8⅝%	**5,500**	5,750
1993, 9%	**9,974**	10,372
1994, 6¼%	**—**	1,615
1996, 7%	**11,875**	12,716
2006, 8.85%	**35,014**	35,015
2007, 11⅛%	**9,300**	9,300
Notes due—		
1984, 3%, 6⅜%	**—**	196
1986, 4½%	**3,887**	3,937
1986, variable rate 10.78% in 1984 and 9.60% in 1983	**26,000**	26,000
1986, variable rate 11.21% in 1984 and 10.83% in 1983	**4,000**	4,000
1986, variable rate 11.21% in 1984 and 10.83% in 1983	**10,000**	10,000
1987, 4.90%	**2,555**	2,590
1988, 3⅞%	**3,286**	3,332
1992, 5⅝%	**8,254**	8,363
1994, 6¼%	**—**	502
1995, 8⅛%	**6,381**	6,580
1997, 6⅛%	**4,926**	4,956
1997, 6¼%	**4,939**	4,975
1998, 8⅝%	**15,454**	15,777
2000, 10⅜%	**12,237**	12,398
2001, 9¼%	**3,400**	3,600
2002, 7¼%	**3,727**	3,810
Less current sinking fund requirements and maturities	**(1,949)**	(1,965)
Total subsidiary companies' long-term debt	**178,760**	183,819
Total long-term debt	**200,721**	206,303
Total capitalization	**$469,715**	$449,396

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

Consolidated Statements of Changes in Common Shareholders' Investment

Commonwealth Energy System and Subsidiary Companies

Years Ended December 31, 1984, 1983 and 1982

	Shares	Par Value $4 Per Share	Amounts Paid in Excess of Par Value	Retained Earnings	Total
			(Dollars in Thousands)		
Balance December 31, 1981	7,926,245	$31,705	$39,107	$ 93,928	$164,740
Add (Deduct)—					
Net income	—	—	—	23,597	23,597
Sale of shares	368,878	1,475	4,005	—	5,480
Cash dividends declared—					
Common shares—					
$1.90 per share	—	—	—	(15,455)	(15,455)
Preferred shares	—	—	—	(3,734)	(3,734)
Balance December 31, 1982	8,295,123	33,180	43,112	98,336	174,628
Add (Deduct)—					
Net income	—	—	—	42,728	42,728
Sale of shares	301,679	1,207	5,065	—	6,272
Cash dividends declared—					
Common shares—					
$2.04 per share	—	—	—	(17,314)	(17,314)
Preferred shares	—	—	—	(3,601)	(3,601)
Balance December 31, 1983	8,596,802	34,387	48,177	120,149	202,713
Add (Deduct)—					
Net income	—	—	—	44,968	44,968
Sale of shares	307,284	1,229	4,879	—	6,108
Cash dividends declared—					
Common shares—					
$2.27 per share	—	—	—	(19,932)	(19,932)
Preferred shares	—	—	—	(3,423)	(3,423)
Balance December 31, 1984	8,904,086	$35,616	$53,056	$141,762	$230,434

Consolidated Statements of Changes in Redeemable Preferred Shares

Years Ended December 31, 1984, 1983 and 1982

	Authorized and Outstanding Cumulative Preferred Shares—$100 Par Value				
	Series A 4.80%	Series B 8.10%	Series C 7.75%	Series D 9.80%	Total Shares
Balance December 31, 1981	44,400	65,600	158,400	189,650	458,050
Less—Sinking fund redemptions	1,200	1,600	5,400	9,650	17,850
Balance December 31, 1982	43,200	64,000	153,000	180,000	440,200
Less—Sinking fund redemptions	1,200	1,600	5,400	10,000	18,200
Balance December 31, 1983	42,000	62,400	147,600	170,000	422,000
Less—Sinking fund redemptions	1,200	1,600	5,400	10,000	18,200
Balance December 31, 1984	40,800	60,800	142,200	160,000	403,800

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

Notes to Financial Statements

Commonwealth Energy System and Subsidiary Companies

1. Significant Accounting Policies

General and Regulatory

Commonwealth Energy System, the parent company, is referred to in this report as the "System" and together with its subsidiaries is sometimes collectively referred to as "the system". The operating companies are regulated by various authorities including the Federal Energy Regulatory Commission (FERC) and the Massachusetts Department of Public Utilities (DPU).

Principles of Consolidation

The consolidated financial statements include the accounts of the System and all of its subsidiary companies. All significant intercompany accounts and transactions have been eliminated in consolidation.

Equity Method of Accounting

The system uses the equity method of accounting for investments in corporate joint ventures. Under this method it records as income the proportionate share of the net earnings of the joint ventures with a corresponding increase in the carrying value of the investment. The investment amount is reduced as cash dividends are received.

The system does business with the corporate joint ventures in which it has investments including: Algonquin Energy, Inc., whose subsidiaries are principal suppliers of natural gas and substitute natural gas for the system; Hopkinton LNG Corp., a liquefied natural gas service company; and four nuclear generating facilities located in New England.

Effective January 1, 1985, the System acquired the remaining 50% equity interest in Hopkinton LNG Corp. from Air Products and Chemicals, Inc.

Operating Revenues

Customers are billed for their use of electricity and gas on a cycle basis throughout the month. To reflect revenues in the proper period, the estimated amount of unbilled sales is recorded each month.

System utility companies are permitted to bill customers for the total costs of purchased power, fuel used in electric production and gas. The amount of such costs incurred but not yet reflected in customers' bills, which totaled $8,321,000 in 1984 and $4,650,000 in 1983, is recorded as unbilled revenues each month.

Depreciation

Depreciation is provided using the straight-line method at rates intended to amortize the original cost of properties over their estimated economic lives. The average composite depreciation rates were as follows:

	1984	1983	1982
Electric	**3.65%**	3.65%	3.64%
Gas	**3.02**	3.02	2.90
Steam	**3.58**	3.59	3.50

Allowance for Funds Used During Construction

Under applicable rate-making practices, system companies are permitted to include an allowance for funds used during construction (AFUDC) as an element of their depreciable property costs. This allowance is based on the amount of Construction Work In Progress which is not included in the rate base on which utility companies earn a return. An amount equal to the AFUDC so capitalized in the current period is reflected in the 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 amount of AFUDC recorded was at a weighted average rate of 11% in 1984, 10% in 1983 and 12% in 1982.

2. Algonquin Energy, Inc.

The System uses the equity method of accounting for its 34.5% investment in Algonquin Energy, Inc.

During 1983, Algonquin and a group of its major customers reached a settlement agreement on several rate matters which date back to 1980. This agreement, approved by FERC, required Algonquin to refund approximately $22,919,000. Algonquin has restated its financial statements for the year 1982 for the effect of the refunds applicable to that year. The restatement had no material effect on the financial statements of the System. Condensed consolidated financial information of Algonquin is as follows:

	1984	1983	1982
	(Dollars in Thousands)		
Condensed Statements of Income			
As reported by Algonquin			
Operating revenues	**$771,170**	$759,744	$746,587
Income before income taxes	**$ 35,833**	$ 33,300	$ 31,068
Provisions for income taxes	**18,647**	17,497	13,040
Net income	**$ 17,186**	$ 15,803	$ 18,028
System equity in Algonquin's net income	**$ 5,933**	$ 5,456	$ 6,224
Adjustment for restatement of Algonquin's previously reported earnings and other	**157**	404	(385)
Reported equity in earnings	**$ 6,090**	$ 5,860	$ 5,839
Condensed Balance Sheets			
As reported by Algonquin			
Total Assets	**$292,668**	$292,458	$330,502
Less—			
Long-term debt	**39,900**	45,600	56,600
Other liabilities and deferred credits	**122,282**	121,505	152,299
Net assets	**$130,486**	$125,353	$121,603
System equity in Algonquin's net assets	**$ 45,049**	$ 43,276	$ 41,982
Adjustment for restatement of Algonquin's previously reported earnings and other	**(207)**	(364)	(769)
Reported equity in net assets	**$ 44,842**	$ 42,912	$ 41,213

Financial statements of Algonquin are included in the System's Annual Report on Form 10-K filed with the Securities and Exchange Commission.

3. Commitments and Contingencies

Construction

The system is engaged in a continuous construction program presently estimated at $328 million for the five-year period ending in 1989, including $85 million in 1985. The program is subject to periodic review and revision.

The largest commitment in the construction program is for the system's 3.52% joint-ownership interest in the Seabrook nuclear project ("the project"). The system's interest is owned by Canal Electric Company for the capacity and energy needs of Cambridge Electric Light Company and Commonwealth Electric Company. The project, which has been under construction since 1976, with Public Service Company of New Hampshire (PSNH) as the lead participant, was originally designed to have two pressurized water reactors, each with a rated capacity of 1,150 megawatts. The project has experienced numerous delays and cost increases.

Various increases in cost-to-complete estimates and delays in the in-service dates for the project have occurred over the years. Based on a late 1986 in-service date and a cost-to-complete estimate (for financial planning purposes) of $1 billion, the system's interest in Unit 1, including AFUDC and nuclear fuel will cost approximately $187 million. At December 31, 1984, the system had expended $125.1 million for its Unit 1 interest. Unit 2 expenditures were approximately $20.9 million.

Regulatory and Financial Developments

On March 30, 1984, PSNH and the other joint-owners voted to cancel Unit 2 on December 1, 1984, subject to certain conditions. This action followed the release of a new project estimate, increasing the cost of both units from $5.24 to $9.0 billion and pushing back the in-service dates from December 1984 and July 1987, to July 1986 and December 1990. As a result, the system discontinued recording AFUDC on its Unit 2 investment on March 31, 1984.

As a result of the serious financial difficulties of PSNH, Unit 1 construction was temporarily suspended on April 18, 1984. In response to these developments, the other joint-owners in the project, including the system, took steps to protect their investment and ensure the option of resuming construction of Unit 1. The joint-owners also modified the Joint Ownership Agreement, subject to necessary regulatory approvals, to permit the transfer of responsibility for completion of construction and operational control of the project from PSNH to a new independent entity, New Hampshire Yankee, currently a division of PSNH. The Nuclear Regulatory Commission has recently approved the transfer of Seabrook's operating license to New Hampshire Yankee.

Construction of Unit 1 resumed in July 1984 at a spending rate of $4 million per week and increased to the present level of $5 million, effective December 1, 1984 (full construction would be approximately $10 million per week). To finance full construction and completion of Unit 1, the joint-owners formulated the Newbrook Plan ("the Plan"). Under the Plan, each joint-owner had to develop a financing program which was acceptable to the other joint-owners. For some joint-owners such plans would require prefinancing of their shares of the estimated construction expenditures. The system qualifies under the Plan to finance its share of the completion costs on a "pay-as-you-go" basis without prefinancing. Additionally, the Plan requires that each joint-owner receive all necessary regulatory approvals.

To date, both the Connecticut and Vermont commissions have issued regulatory approvals, subject to certain conditions. The Vermont decision states that funding of the project by all participants, including all regulatory approvals, must be in place by April 15, 1985. If these conditions are not met, the commission may order the Vermont joint-owners to disengage from the project. Based on their determination that the project is not in the ratepayers' best interest, the Maine commission has ordered that state's joint-owners to seek offers to purchase their aggregate 9.7% ownership interest in Unit 1. Absent any offers considered to be firm and credible by either the utilities or the commission, the companies could be subject to an order to disengage from the project. Proceedings before the New Hampshire Public Utilities Commission for approval of the financing of PSNH's share of the cost of completing Unit 1 have recently concluded and a decision is pending. Hearings on the system's financing petition, which has been before the DPU since late 1983, together with similar petitions of other Massachusetts joint-owners, are expected to conclude in early April, and to be followed by an order shortly thereafter. The success of the Plan and therefore the project, is contingent upon a number of regulatory approvals, some but not all of which have been noted above. The system is unable to determine whether such approvals will be granted.

While the conditions underlying the March 30, 1984 vote to cancel Unit 2 were not met, it became apparent that it is not a viable near-term project. Thus, despite the lack of the required consent of PSNH to a formal cancellation, the system has abandoned its investment in that unit. In 1985, the system will seek regulatory approval to recover its full investment in Unit 2.

Costs associated with Seabrook Units 1 and 2 are subject to a Capacity Acquisition Agreement between Canal Electric and its customers, Cambridge Electric Light Company and Commonwealth Electric Company. This Agreement, which has been accepted for filing as a rate schedule by FERC, entitles Canal to recover from its customers, costs incurred in connection with any unit covered by such Agreement whether or not the unit becomes operational. In turn, Cambridge and Commonwealth would seek to recover those charges billed by Canal from their respective customers through retail rates, which are subject to DPU regulation.

The system believes that its subsidiaries' participation in the project, from its inception, has been prudent, reasonable, appropriate and an integral and necessary element in planning for the power needs of its electric customers. Accordingly, the system will pursue vigorously all rights to the recovery of its investment. However, the system is unable to predict the outcome of future regulatory proceedings, the amount of investment recovery which will be allowed, or the recovery period.

Power Contracts

The system has long-term contracts for the purchase of electricity from various utilities. Generally, these contracts are for fixed periods and require that the system pay a demand charge for its entitlement in the generating capacity of each unit and an energy charge to cover the cost of fuel. Total costs under these contracts are included in electricity purchased for resale in the statements of income and are fully recoverable in revenues under the system's power cost charges.

4. Income Taxes

The system files a consolidated Federal income tax return. For financial reporting purposes, the System and its subsidiaries provide taxes on a separate return basis.

The following is a summary of the consolidated provisions for income taxes for the years ended December 31, 1984, 1983 and 1982:

	1984			1983			1982		
	Total	Federal	State	Total	Federal	State	Total	Federal	State
				(Dollars in Thousands)					
Currently payable	**$15,240**	**$11,922**	**$3,318**	$26,177	$21,740	$4,437	$ 561	$ (91)	$ 652
Currently deferred	**(3,494)**	**(2,996)**	**(498)**	(5,772)	(4,951)	(821)	4,933	3,423	1,510
Long-term deferred	**16,000**	**14,914**	**1,086**	6,568	5,867	701	6,063	5,489	574
Investment tax credits, net	**1,398**	**1,398**	—	3,736	3,736	—	4,230	4,230	—
Tax on gain from sale of buildings	**2,103**	**1,704**	**399**	—	—	—	—	—	—
Tax credit on unrecoverable nuclear projects	—	—	—	—	—	—	(942)	(818)	(124)
	$31,247	**$26,942**	**$4,305**	$30,709	$26,392	$4,317	$14,845	$12,233	$2,612

Income taxes are provided for the tax effects of all timing differences. Timing differences result from reporting income and expense for tax purposes in periods different from those used for financial reporting purposes. The accumulated deferred income taxes resulting from long-term timing differences are presented as reductions in the assets to which they relate, consistent with rate-making treatment. Additionally, Construction Work In Progress is presented net of accumulated deferred income taxes which totaled $12,741,000 in 1984 and $10,246,000 in 1983. Deferred charges have also been presented net of accumulated deferred income taxes which totaled $8,944,000 in 1984 and $214,000 in 1983.

The system's long-term deferred provision for income taxes results from the use of the following:

	1984	1983	1982
		(Dollars in Thousands)	
Abandonment of Seabrook Unit 2	**$ 6,626**	$ —	$ —
Accelerated depreciation for tax purposes	**5,061**	3,766	4,358
Capitalized interest during construction	**5,262**	4,123	3,919
Cancelled nuclear units	**(635)**	(1,424)	(2,510)
Other	**(314)**	103	296
Long-term deferred income tax provision	**$16,000**	$ 6,568	$ 6,063

The tax effects of unbilled revenue and other current timing differences are included in the current deferred provision and accrued income taxes. Investment tax credits are deferred and amortized over the life of the property giving rise to the credits.

Income taxes totaling approximately $2,703,000 at December 31, 1984 have not been provided on the undistributed earnings of Algonquin Energy, Inc. because such earnings are expected to be reinvested indefinitely.

The total income tax provision set forth above represents 41% in 1984, 42% in 1983 and 39% in 1982 of income before such taxes. The following table reconciles the statutory Federal income tax rate to these percentages:

	1984	1983	1982
Statutory Federal income tax rate	**46%**	46%	46%
Increase (Decrease) from statutory rate:			
Effect of capital gain from sale of buildings	**(1)**	—	—
Effect of dividend received deduction	**(4)**	(4)	(8)
State tax net of Federal tax benefit	**3**	3	4
Amortization of investment tax credits	**(2)**	(2)	(2)
Allowance for equity funds used during construction	**(2)**	(2)	(3)
Other, net	**1**	1	2
	41%	42%	39%

5. Redeemable Preferred Shares

The System's four series of preferred shares have been issued at par value, $100 per share, and are subject to periodic, mandatory sinking fund payments. The System can make additional voluntary redemptions, not exceeding the required redemption, at par, on a non-cumulative basis, on each sinking fund date. Preferred shares may also be called for redemption, in whole or in part, in excess of the required and voluntary sinking fund redemptions. The obligation to make the mandatory redemptions is cumulative and the System is not allowed to pay dividends to common shareholders or make any optional sinking fund payments if mandatory redemptions are in arrears. Details of redemptions for the four series of Cumulative Preferred Shares are contained in the following table:

	Dividend Rate	Sinking Funds 1985-1989 Mandatory	Optional	Optional Redemption Call Prices
		(Dollars in Thousands)		
Series A	4.80%	$ 120	$ 120	$102
Series B	8.10	160	160	108 to 101
Series C	7.75	540	540	103 to 101
Series D	9.80	1,000	1,000	110 to 101

Preferred shareholders have no voting rights except in the event that six full quarterly dividends have not been paid. In this circumstance, the preferred shareholders are entitled, voting as a class, to elect two of the nine Trustees of the System.

The preference of these shares in involuntary liquidation is equal to par value. The shares are of equal rank and are entitled to cumulative dividends at the annual rate established for each series. No dividend can be declared on any series unless proportionate dividends are concurrently declared on the other outstanding series and in the event that dividend payments are in arrears, the System may not redeem any shares unless all shares of all preferred series are redeemed.

6. Dividend Restriction

At December 31, 1984, approximately $31,102,000 of consolidated retained earnings was restricted against the payment of cash dividends by terms of the indentures securing long-term debt. As of the same date, retained earnings included approximately $43,032,000 representing the system's equity in undistributed earnings of corporate joint ventures.

7. Interim Financing and Long-Term Debt

Notes Payable to Banks

System companies have banking relationships under which borrowings are arranged as required for interim financing of their construction programs. The borrowings are unsecured and are evidenced by notes having maturities of 90 days or less which are renewable at maturity. Lines of credit with banks, against which these notes are applied, total $135,000,000. At December 31, 1984, notes payable totaled $53,400,000.

The terms of one line of credit require the payment of a fee equal to 1/4 of 1% of the line. Another line requires that when the system is borrowing, it must maintain normal operating balances for cash demand and bank service charges.

The interest rate on the outstanding borrowings is at the lower of the prime or an adjusted money market rate.

Long-Term Debt Maturities

Under terms of their various indentures, the System and certain subsidiary companies are required to make periodic sinking fund payments for retirement of outstanding long-term debt. The required sinking fund payments and balances of maturing debt issues for the five years subsequent to December 31, 1984 are as follows:

Year	Sinking Fund Payments System	Subsidiaries	Maturing Debt Issues	Total
		(Dollars in Thousands)		
1985	$521	$1,949	$ —	$ 2,470
1986	522	3,791	49,225	53,538
1987	364	3,756	15,237	19,357
1988	280	3,711	5,822	9,813
1989	280	3,711	10,000	13,991

8. Employee and Postretirement Benefits

The system has a noncontributory pension plan covering substantially all regular employees who have attained the age of 21. Pension costs are funded as accrued and include amounts applicable to prior service costs which are being amortized over a period of 30 years. Total pension expense was approximately $6,731,000 in 1984, $6,067,000 in 1983 and $5,324,000 in 1982. The assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7 1/2% in each of these years.

A comparison of accumulated benefits and net assets for the system's benefit plan is presented below:

	January 1, 1984	1983
	(Dollars in Thousands)	
Actuarial present value of accumulated plan benefits:		
Vested	**$76,353**	$66,686
Nonvested	**1,391**	1,236
	$77,744	$67,922
Net assets available for benefits	**$71,726**	$60,983

In addition to providing pension benefits, the system provides certain health care and life insurance benefits for retired employees. Substantially all of the system's employees may become eligible for those benefits if they reach normal retirement age while working for a subsidiary company of the system, or if their age plus years of service at (early) retirement equals 75 or more. The cost of retiree health care and life insurance benefits is recognized as expense as claims are paid and totaled $903,000 in 1984.

The system has an Employees Savings Plan which provides for system contributions equal to contributions by eligible employees but not in excess of four percent of each employee's compensation rate. The total system contribution was approximately $2,537,000 in 1984, $2,163,000 in 1983 and $1,947,000 in 1982.

9. Sale of Buildings

In September 1984, COM/Energy Realty Trust and COM/Energy Cambridge Realty, wholly-owned subsidiaries of the System, sold the System's corporate headquarters office complex located in Cambridge, Massachusetts. The sale yielded an after-tax gain of approximately $6.1 million, $4.3 million of which was recognized in 1984. Due to the lease-back and continued occupancy of the properties by certain subsidiaries of the System, accounting principles require that the remaining $1.8 million of the after-tax gain be deferred and amortized ratably over the lease term which is scheduled to expire on September 30, 1986.

10. Lease Obligations

Financial Accounting Standards Board (FASB) Statement No. 71 requires that leases of regulated public utilities, which otherwise meet the criteria for capitalization under FASB Statement No. 13, be capitalized even though such leases are treated as operating leases for rate-making purposes. Accordingly, in 1984, system companies recorded their capital lease obligations and retroactively reflected the effect of such leases in their balance sheet as of December 31, 1983 in accordance with the provisions of FASB Statement No. 71.

System companies lease property and equipment under agreements ranging in length from two to forty-four years. Generally, these agreements require the lessee to pay related property taxes, maintenance costs and other costs of operation. The system anticipates that in the normal course of business, leases will generally be renewed or replaced by other leases. Leases currently in effect contain no provisions which prohibit system companies from entering into future lease agreements or obligations.

The following is an analysis, by major classes, of property under capital leases at December 31, 1984 and 1983:

	1984	1983
	(Dollars in Thousands)	
Office furniture and equipment	**$ 6,605**	$ 4,122
Transportation equipment	**4,235**	4,046
Other	**464**	464
	11,304	8,632
Less: Accumulated amortization	**782**	156
	$10,522	$ 8,476

Future minimum lease payments, by period and in the aggregate, of capital leases and non-cancellable operating leases consisted of the following at December 31, 1984:

	Capital Leases	Operating Leases
	(Dollars in Thousands)	
1985	$ 3,854	$ 994
1986	3,848	642
1987	3,401	173
1988	1,769	131
1989	67	111
Beyond 1989	—	1,416
Total future minimum lease payments	12,939	$3,467
Less: Estimated interest element included therein	2,417	
Estimated present value of future minimum lease payments	$10,522	

Total rent expense for all operating leases, except those with terms of a month or less, amounted to $2,022,000 in 1984, $1,222,000 in 1983 and $1,299,000 in 1982. There were no contingent rentals and no sublease rentals for the years 1984, 1983 and 1982.

11. Segment Information

System companies provide electric, gas and steam services to retail customers in service territories located in central and eastern Massachusetts and, in addition, sell electricity at wholesale to Massachusetts customers. Other operations of the system include the development and operation of rental properties and other activities which do not presently contribute significantly to either revenues or operating income.

Operating income of the various industry segments includes income from transactions with affiliates and is exclusive of interest expense, income taxes, and equity in earnings of unconsolidated corporate joint ventures which provide energy and services for the system's gas operations.

The amount of identifiable assets represented by the system's investment in corporate joint ventures consists principally of a percentage ownership in the assets of Algonquin Energy, Inc., whose principal subsidiary is a regulated natural gas transmission company operating in the northeastern United States; Hopkinton LNG Corp. which operates in the system's franchise areas; and four regional electric generating plants.

	1984	1983	1982
		(Dollars in Thousands)	
Revenues from Unaffiliated Customers:			
Electric	**$465,891**	$356,895	$361,908
Gas	**242,617**	246,224	231,003
Steam and other	**15,139**	16,536	14,170
Total Consolidated Revenues	**$723,647**	$619,655	$607,081
Operating Income Before Income Taxes:			
Electric	**$ 49,507**	$ 47,153	$ 37,424
Gas	**21,418**	24,274	9,097
Steam and other	**1,674**	3,055	1,340
Total Consolidated Operating Income	**$ 72,599**	$ 74,482	$ 47,861
Identifiable Assets:			
Electric	**$479,169**	$446,984	$402,067
Gas	**176,915**	171,560	162,548
Steam and other	**24,660**	20,125	15,038
	680,744	638,669	579,653
Intercompany eliminations	**(50,975)**	(26,082)	(17,763)
Investment in corporate joint ventures	**57,412**	55,825	53,616
Total Consolidated Assets	**$687,181**	$668,412	$615,506
Depreciation Expense:			
Electric	**$ 15,813**	$ 15,285	$ 14,734
Gas	**4,372**	4,109	3,785
Steam and other	**401**	452	417
Total Consolidated Depreciation	**$ 20,586**	$ 19,846	$ 18,936

Additional segment information relating to property additions is shown in the Consolidated Statements of Sources of Funds Used for Construction.

12. Supplementary Information to Disclose the Effects of Changing Prices (Unaudited)

The following supplementary information is supplied in accordance with the requirements of Financial Accounting Standards Board Statement No. 33, as amended by Statement No. 82, for the purpose of providing certain information about the effects of changing prices. It should be viewed as an estimate of the approximate effect of inflation, rather than as a precise measure.

Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present and is determined primarily by indexing surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. Since the utility plant is not expected to be replaced in kind, current cost does not necessarily represent the replacement cost of the system's productive capacity. Depreciation is determined by applying the system's depreciation rates to the revised asset amounts.

Fuel inventories, the cost of fuel used in generation and cost of gas sold have not been restated from their historical cost in nominal dollars. Regulation provides for the recovery of fuel and purchased gas costs through the operation of adjustment clauses. For this reason fuel inventories are effectively monetary assets. Since only historical costs are deductible for income tax purposes, the income tax expense in the historical cost financial statements is not adjusted.

Under present rate-making procedures prescribed by the regulatory commissions, only the historical cost of plant is recoverable in revenues as depreciation. Because the excess cost of plant stated in terms of current cost is not recoverable in rates, a write-down to net recoverable cost is required. While the rate-making process does not recognize the current cost of replacing plant, regulated companies have, historically, been allowed to earn a return on the increased cost of its investment when replacement actually occurs.

During periods of inflation, holders of monetary assets suffer a loss of general purchasing power while holders of monetary liabilities experience a gain. The gain from the decline in purchasing power of net amounts owed is primarily attributable to the substantial amount of debt which has been used to finance property, plant and equipment. These gains are unrealized and, therefore, do not contribute to cash flow or distributable income.

Five Year Comparison of Selected Supplementary Financial Data Adjusted for Effects of Changing Prices (In Thousands of Average 1984 Dollars)

Year Ended December 31,	**1984**	1983	1982	1981	1980
Operating Revenues:					
Actual	**$723,647**	$619,655	$607,081	$563,455	$512,535
Adjusted to average 1984 dollars	**$723,647**	$646,028	$653,279	$643,505	$646,068
Current Cost Information—					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	**$ 9,903**	$ 9,397	$ (9,664)	$ (8,536)	$ (162)
Income (loss) per common share (after dividend requirements on preferred stock)	**$ .74**	$ .69	$ (1.65)	$ (1.59)	$ (.55)
Excess of increase (decrease) in general price level over increase in specific prices after adjustment to net recoverable cost	**$ (14,032)**	$ (14,293)	$ (15,354)	$ 5,727	$ 24,123
Net assets at year-end at net recoverable cost	**$227,220**	$207,790	$185,796	$182,062	$191,305
General Information—					
Gain from decline in purchasing power of net amounts owed	**$ 14,451**	$ 13,345	$ 12,805	$ 26,058	$ 33,147
Cash dividends declared per common share	**$ 2.27**	$ 2.13	$ 2.04	$ 2.15	$ 2.13
Market price per common share at year-end	**$ 24.50**	$ 19.86	$ 19.15	$ 16.44	$ 17.21
Average consumer price index	**311.1**	298.4	289.1	272.4	246.8

Statement of Income from Continuing Operations Adjusted for Changing Prices For the Year Ended December 31, 1984

	Conventional Historical Cost	Current Cost Average 1984 Dollars
	(Dollars in Thousands)	
Operating revenues	$723,647	$723,647
Operation, maintenance and other	658,093	658,093
Depreciation	20,586	55,651
Total	678,679	713,744
Income from continuing operations (excluding reduction to net recoverable cost)	$ 44,968	$ 9,903
Increase in specific prices (current cost) of property, plant and equipment held during the year*		$ 16,207
Adjustment to net recoverable cost		35,557
Effect of increase in general price level		(37,732)
Excess of specific prices over the increase in general price level after adjustment to net recoverable cost		14,032
Gain from decline in purchasing power of net amounts owed		14,451
Net		$ 28,483

* At December 31, 1984, current cost of property, plant and equipment, net of accumulated depreciation was $964,659,000 while historical cost or net cost recoverable through depreciation was $535,342,000.

Selected Financial Data

	1984	1983	1982	1981	1980
(In Thousands Except Common Share Data)					
Operating Revenues:					
Electric	**$465,891**	$356,895	$361,908	$361,154	$326,050
Gas	**242,617**	246,224	231,003	187,039	169,807
Steam and other	**15,139**	16,536	14,170	15,262	16,678
Total	**$723,647**	$619,655	$607,081	$563,455	$512,535
Net Income	**$ 44,968**	$ 42,728	$ 23,597	$ 21,257	$ 26,925
Common Share Data—					
Earnings per share	**$4.75**	$4.63	$2.45	$2.22	$3.01
Dividends declared per share	**$2.27**	$2.04	$1.90	$1.88	$1.69
Weighted average shares outstanding	**8,747,626**	8,451,316	8,103,922	7,817,321	7,604,290
Total Assets	**$687,181**	$668,412	$615,506	$563,702	$561,211
Long-term debt	**$200,721**	$206,303	$186,374	$184,042	$173,764
Redeemable preferred share investment	**38,560**	40,380	42,200	44,020	45,840
Common share investment	**230,434**	202,713	174,628	164,740	158,898
Total Capitalization	**$469,715**	$449,396	$403,202	$392,802	$378,502

	1984 by Quarter			
	1st	**2nd**	**3rd**	**4th**
	(Dollars in Thousands Except Per Share Amounts)			
Operating Revenues	**$224,168**	**$153,554**	**$159,913**	**$186,012**
Operating Income	**17,500**	**9,288**	**10,526**	**6,141**
Income Before Interest Charges	**21,939**	**10,713**	**14,386**	**12,006**
Net Income	**16,236**	**6,779**	**10,581**	**11,372**
Earnings per Common Share*	**1.78**	**.68**	**1.10**	**1.19**
Dividends Declared per Common Share	**.53**	**.58**	**.58**	**.58**
Closing Price of Common Shares—				
High	**21⅝**	**20**	**21¼**	**25**
Low	**17⅞**	**16¾**	**17⅝**	**20¼**

	1983 by Quarter			
	1st	2nd	3rd	4th
	(Dollars in Thousands Except Per Share Amounts)			
Operating Revenues	$205,617	$131,054	$118,709	$164,275
Operating Income	15,491	7,527	7,629	13,126
Income Before Interest Charges	19,213	11,963	10,349	16,510
Net Income	14,891	7,793	6,838	13,206
Earnings per Common Share*	1.67	.82	.70	1.44
Dividends Declared per Common Share	.49	.49	.53	.53
Closing Price of Common Shares—				
High	20	22	22¼	23¾
Low	18⅛	18¾	19½	19

*The quarterly amounts for earnings per common share are derived from amounts previously reported on a year-to-date basis and have been computed using the weighted average number of common shares outstanding during the periods.

Comparative Statistical Data—1984-1975

Commonwealth Energy System and Subsidiary Companies

	1984	1983	1982	1981	1980
Operations (Dollars in Thousands)					
Revenues	**$723,647**	$619,655	$607,081	$563,455	$512,535
Operating expenses—					
Operations	**583,770**	479,883	491,569	453,787	394,683
Maintenance	**28,899**	25,780	26,371	24,410	21,702
Depreciation	**20,586**	19,846	18,936	18,188	17,172
Taxes	**46,937**	50,373	38,131	38,114	43,878
Total	**680,192**	575,882	575,007	534,499	477,435
Operating income	**43,455**	43,773	32,074	28,956	35,100
Other income	**15,589**	14,262	8,504	10,863	9,097
Total income	**59,044**	58,035	40,578	39,819	44,197
Interest charges	**14,076**	15,307	16,981	18,562	17,272
Net income	**44,968**	42,728	23,597	21,257	26,925
Preferred dividends	**3,423**	3,601	3,734	3,898	4,033
Earnings applicable to common shares	**$ 41,545**	$ 39,127	$ 19,863	$ 17,359	$ 22,892
Sources of Consolidated Net Income—					
Electric	**$ 23,588**	$ 24,382	$ 15,172	$ 12,401	$ 15,550
Gas	**8,251**	10,929	1,162	3,306	6,135
Steam and other	**13,129**	7,417	7,263	5,550	5,240
Total	**$ 44,968**	$ 42,728	$ 23,597	$ 21,257	$ 26,925
Financial (Dollars in Thousands)					
Property, plant and equipment (including construction work in progress, net)	**$741,710**	$718,038	$663,245	$613,216	$559,772
Accumulated depreciation	**216,514**	202,265	186,673	174,298	160,654
Accumulated deferred income taxes	**75,507**	70,732	64,328	61,656	54,475
Capitalization—					
Long-term debt	**$200,721**	$206,303	$186,374	$184,042	$173,764
Preferred shares	**38,560**	40,380	42,200	44,020	45,840
Common equity	**230,434**	202,713	174,628	164,740	158,898
Total	**$469,715**	$449,396	$403,202	$392,802	$378,502
Statistics and Ratios					
Unit sales—(In Thousands) KWH—Retail	**3,552,535**	3,349,755	3,164,336	3,072,810	3,121,583
Wholesale	**2,557,652**	1,396,427	2,109,969	2,230,786	2,418,540
MCF —Firm	**32,568**	30,830	32,448	32,309	33,174
Interruptible	**4,741**	4,717	3,844	3,586	3,571
Capitalization ratios—					
Long-term debt	**42.7%**	45.9%	46.2%	46.9%	45.9
Preferred shares	**8.2**	9.0	10.5	11.2	12.1
Common equity	**49.1**	45.1	43.3	41.9	42.0
Total	**100.0%**	100.0%	100.0%	100.0%	100.0
Return on common equity	**19.2%**	20.7%	11.7%	10.7%	15.0
Common share dividend pay-out	**48.0%**	44.3%	77.8%	84.9%	56.3
Average price/earnings ratio	**4.4**	4.5	6.5	6.4	4.7
Data Per Common Share					
Earnings per share*	**$ 4.75**	$ 4.63	$ 2.45	$ 2.22	$ 3.01
Dividends paid	**2.22**	2.00	1.88	1.84	1.66
Annual dividend rate at end of year	**2.32**	2.12	1.96	1.88	1.72
Book value	**25.88**	23.58	21.05	20.78	20.65
Common share closing price range—					
High	**25**	23¾	19	15¾	16¾
Low	**16¾**	18¾	13	12¾	11¾

*Based on the weighted average number of shares outstanding.

1979	1978	1977	1976	1975
$386,843	$339,195	$359,746	$324,277	$288,330
285,678	236,264	255,942	230,879	216,433
16,422	15,505	14,174	10,819	9,305
16,721	16,119	15,590	14,439	10,910
37,770	41,277	42,368	37,427	27,205
356,591	309,165	328,074	293,564	263,853
30,252	30,030	31,672	30,713	24,477
7,170	6,490	4,463	4,360	3,179
37,422	36,520	36,135	35,073	27,656
14,707	14,652	14,676	16,785	14,266
22,715	21,868	21,459	18,288	13,390
4,093	4,154	4,183	3,042	2,260
$ 18,622	$ 17,714	$ 17,276	$ 15,246	$ 11,130
$ 13,939	$ 14,165	$ 14,578	$ 12,376	$ 10,150
5,257	4,817	4,837	2,375	931
3,519	2,886	2,044	3,537	2,309
$ 22,715	$ 21,868	$ 21,459	$ 18,288	$ 13,390
$528,674	$504,160	$484,848	$466,621	$445,257
147,068	133,470	121,019	109,473	99,363
47,096	43,137	38,668	35,463	25,984
$177,471	$180,056	$186,699	$190,532	$154,553
47,660	48,480	49,300	50,120	30,400
146,240	138,133	130,551	122,843	111,102
$371,371	$366,669	$366,550	$363,495	$296,055
,048,612	2,974,570	2,888,557	2,825,076	2,651,377
,586,954	2,687,955	3,023,877	3,319,815	2,970,122
29,590	30,795	29,063	30,158	29,006
4,549	4,674	3,648	2,156	1,085
47.8%	49.1%	50.9%	52.4%	52.2%
12.8	13.2	13.5	13.8	10.3
39.4	37.7	35.6	33.8	37.5
100.0%	100.0%	100.0%	100.0%	100.0%
13.1%	13.2%	13.6%	13.0%	10.6%
64.1%	62.6%	60.3%	62.7%	76.4%
6.1	6.9	7.2	6.8	6.5
$ 2.50	$ 2.40	$ 2.36	$ 2.15	$ 1.71
1.58	1.48	1.40	1.31	1.28
1.60	1.52	1.44	1.36	1.28
19.48	18.63	17.75	16.82	16.21
16⅞	18⅜	18⅞	16⅜	13½
13½	15	15⅜	12¾	8⅞

System Facts

Commonwealth Energy System and Subsidiary Companies

System Companies

Electric

Cambridge Electric Light Company
Canal Electric Company
Commonwealth Electric Company

Gas

Commonwealth Gas Company

Steam

COM/Energy Steam Company

Other Companies

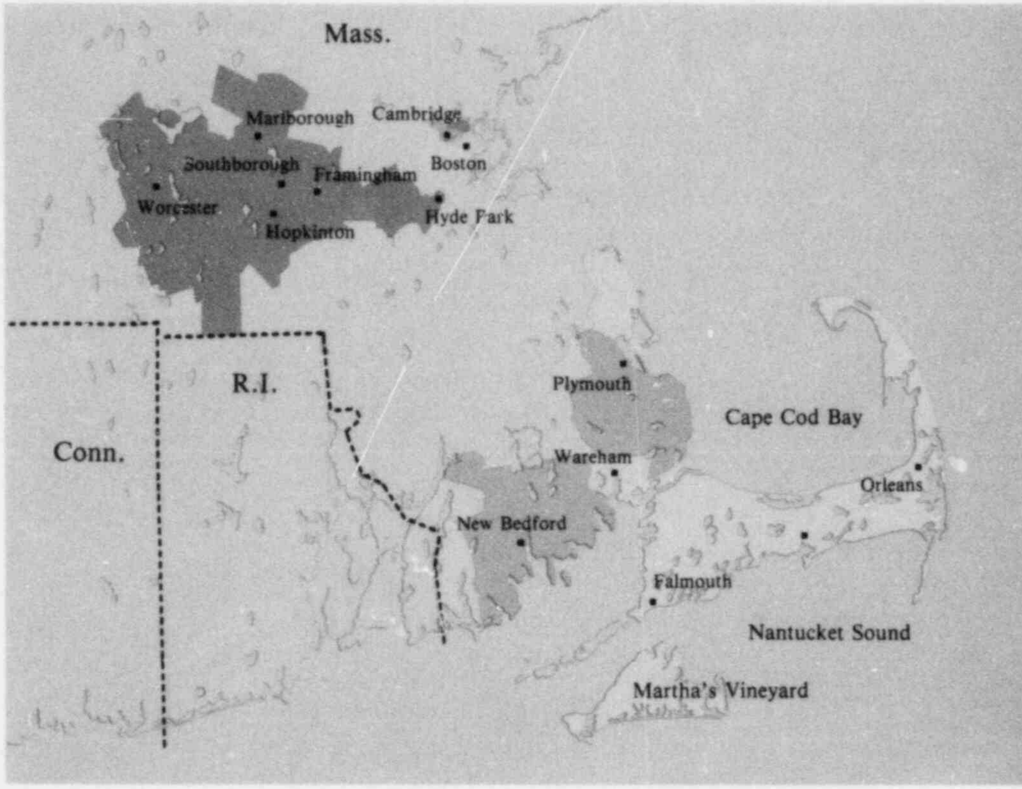
COM/Energy Services Company (service company)
COM/Energy Acushnet Realty (leases land to Hopkinton LNG Corp.)
COM/Energy Cambridge Realty (organized to hold various system non-utility properties)
COM/Energy Realty Trust (organized to own property in Massachusetts)
COM/Energy Research Park Realty (organized to develop a research complex in Cambridge)
Darvel Realty Trust (joint-owner of the Riverfront Office Park complex)
Hopkinton LNG Corp. (LNG service company)

In addition, the System owns 34.5% of Algonquin Energy, Inc., whose subsidiaries are principal suppliers of natural gas and SNG to the system.

The system has a 1.4% interest in a jointly-owned oil-fired generating unit and also owns from 2½% to 4½% interests in four nuclear power plants (located in Massachusetts, Connecticut, Vermont and Maine).

Territory of Utility Operating Companies

Electric Operations—1,112 square miles covering 41 communities with population of 560,000
Gas Operations—1,012 square miles covering 47 cities and towns (including 12 served with electricity) with population of 991,000



Gas Service Area   Electric Service Area   Gas and Electric Service Area

Customers

Electric—296,000 (including 52,000 seasonal)
Gas—205,000

Employees and Shareholders at Year-End

Employees—2,451
Shareholders—22,218

Electric Plant

Capability—1,262,400 KW, including sales under long-term contracts with other utilities of 426,000 KW resulting in a net capability of 836,400 KW

Peak demand—719,000 KW on January 21, 1985

Gas Plant

Distribution lines—2,404 miles
Peak day send-out—288,141 MCF on January 21, 1985

Commonwealth Energy System
Post Office Box 190
Cambridge, Massachusetts 02139
Telephone (617) 864-3100

Trustees and Officers

Commonwealth Energy System and Subsidiary Companies

Trustees Under Indentures of Trust

The First National Bank of Boston — The System's Bonds

Citibank, N.A. — Canal Electric Company Series B and D Bonds

State Street Bank and Trust Company — Other Subsidiary Companies' Long-term Debt and the System's Bond Sinking Funds

Form 10-K

The System files annually a report on Form 10-K with the Securities and Exchange Commission. Many of the information requirements of Form 10-K are satisfied by this 1984 Annual Report. However, a copy of Form 10-K is available upon written request addressed to Michael P. Sullivan, Vice President, Secretary and General Attorney, Commonwealth Energy System, P. O. Box 190, Cambridge, Massachusetts 02139.

System Management

Corporate Division

* **Gerald E. Anderson,** President and Chief Executive Officer

William F. Burt, Assistant to the President

* **Earl G. Cheney,** Financial Vice President

* **Forest W. Grumney,** Vice President — Human Resources

* **John J. Molloy,** Vice President — Public Relations

* **Michael P. Sullivan,** Vice President, Secretary and General Attorney

J. James Tasillo, Jr., Vice President — Rates

Walter J. Cotting, Assistant Vice President — Information Services

Robert S. Parker, Treasurer

John A. Whalen, Comptroller

Electric Division

* **Jeremiah V. Donovan,** President and Chief Operating Officer

S. Robert Fox, Jr., Vice President — Facilities Development

Andrew S. Griffiths, Vice President — Administration

Robert E. Healey, Vice President — Human Resources

Ronald F. MacDonald, Vice President — Customer Services

William R. Smith, Vice President — Energy Supply

Gas Division

* **William G. Poist,** President and Chief Operating Officer

Donald Johnson, Vice President — Customer Services

Harold A. Melden, Vice President — Gas Supply

Franklin J. Morrison, Vice President — Facilities Development

John R. Williams, Vice President — Human Resources and Administration

* Member of Policy Committee

Shareholder Questionnaire

The purpose of this questionnaire is to establish a shareholder data base which will enable us to more fully satisfy your informational needs. Please check the appropriate box or boxes for each question. After completing the questionnaire, please fold as directed and return it at your earliest convenience. Thank you.

General

- Age
  - ☐ Under 25 ☐ 51-64
  - ☐ 25-50 ☐ 65 or over
- Sex
  - ☐ Male ☐ Female
- Marital Status
  - ☐ Single ☐ Widower
  - ☐ Married ☐ Widow
- Occupation
  - ☐ Retired ☐ Homemaker
  - ☐ Professional ☐ Student
  - ☐ Managerial ☐ Craftsman
  - ☐ Government ☐ Laborer
  - ☐ Office worker ☐ Other
  - ☐ Self-employed
- Total Family Income
  - ☐ Minor, receiving little or no income
  - ☐ Less than $20,000 ☐ 60,001 - 80,000
  - ☐ 20,001 - 40,000 ☐ 80,001 - 100,000
  - ☐ 40,001 - 60,000 ☐ Greater than 100,000
- Level of Education
  - ☐ Some High School or Grade School
  - ☐ High School diploma
  - ☐ Trade/Technical
  - ☐ Some College
  - ☐ College degree
  - ☐ Post graduate work or degree
- Number of shares you own
  - ☐ 1 - 49 ☐ 251 - 500
  - ☐ 50 - 99 ☐ 501 - 1000
  - ☐ 100 - 250 ☐ 1000 or more
- Years of ownership
  - ☐ less than one year ☐ 11 to 15
  - ☐ 1 to 5 ☐ 16 to 20
  - ☐ 6 to 10 ☐ over 20
- Which of the following were instrumental to your investment in COM/Energy?
  - ☐ Self motivated ☐ Financial publication
  - ☐ Inheritance ☐ COM/Energy employee
  - ☐ Gift ☐ COM/Energy shareholder
  - ☐ Broker/Banker
  - ☐ Financial analyst ☐ Other ____________
- Rate in order of importance, your reason for buying COM/Energy stock ("1" being most important)
  - ☐ Dividends ☐ Investment security
  - ☐ Stock appreciation
- How well has your COM/Energy investment satisfied your investment goals?
  - ☐ Very well ☐ Poorly
  - ☐ Adequately
- Do you own stock in other companies?
  - ☐ Yes ☐ No

  If yes, how has your COM/Energy investment performed in comparison to these other investments?

  Far Superior ----------Equal to----------► Worse
  1 2 3 4 5

- Have you increased your initial investment in COM/Energy?
  - ☐ Yes ☐ No
- Do you plan to in the future?
  - ☐ Yes ☐ No

Reports to Shareholders

- Which parts of the Annual Report did you read?
  - ☐ Entire report
  - ☐ President's Letter
  - ☐ Management's Discussion and Analysis
  - ☐ Shareholder Information
  - ☐ Year in Review
  - ☐ Financial Statements and Notes
- Is the 1984 Annual Report easy to read and understand?
  - ☐ Very ☐ Difficult
  - ☐ Somewhat ☐ Very difficult
- Overall, I feel that the 1984 Annual Report is—

  Outstanding -------------Good-------------► Poor
  1 2 3 4 5

Shareholder Services

- What do you think of the level of service provided to you in connection with your shareholder account(s)?

  Outstanding -------------Good-------------► Poor
  1 2 3 4 5

- What improvements or additional features would you recommend in the Shareholder Services area?

  Comments: ______________________________

  ____

  ____

  ____

  ____

- Would you attend informal informational meetings of shareholders in your region if the number of responses made it practical?
  - ☐ Yes ☐ No
- Please list the city and state of your principal residence.

  ____

  ____

- Please list below any additional comments you might have regarding this questionnaire or COM/Energy in general.

  Comments: ______________________________

  ____

  ____

  ____

  ____

PEEL, FOLD IN HALF AND PRESS

TO EXPOSE ADHESIVE, REMOVE LINER TO EXPOSE ADHESIVE, REMOVE LINER TO EXPOSE ADHESIVE, REMOVE LINER

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IF MAILED
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UNITED STATES

BUSINESS REPLY MAIL

FIRST CLASS PERMIT NO. 25832 BOSTON, MA

POSTAGE WILL BE PAID BY ADDRESSEE

COM/Energy

Commonwealth Energy System
Attention: Shareholder Services
Post Office Box 190
Cambridge, Massachusetts 02139