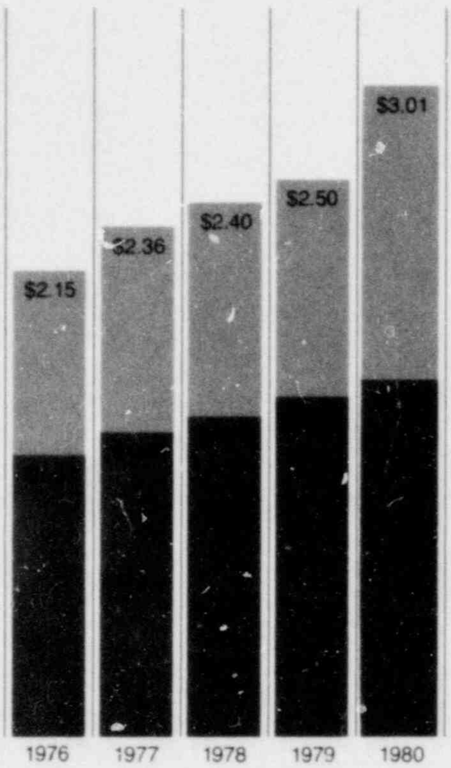
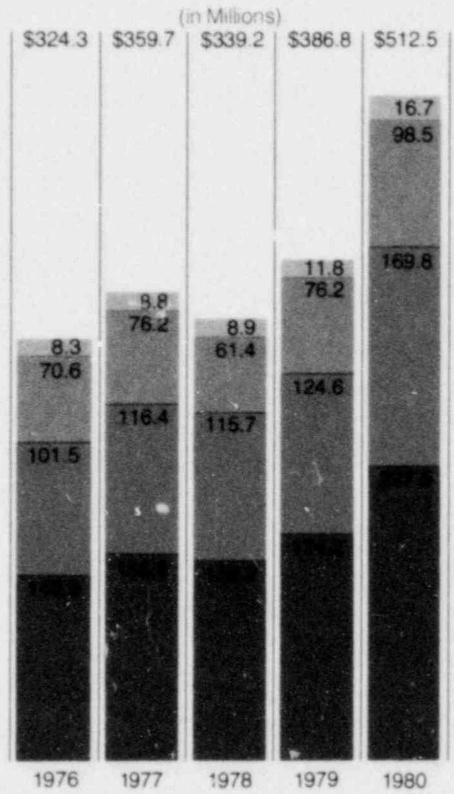
New England Gas and Electric Association 1980 Annual Report



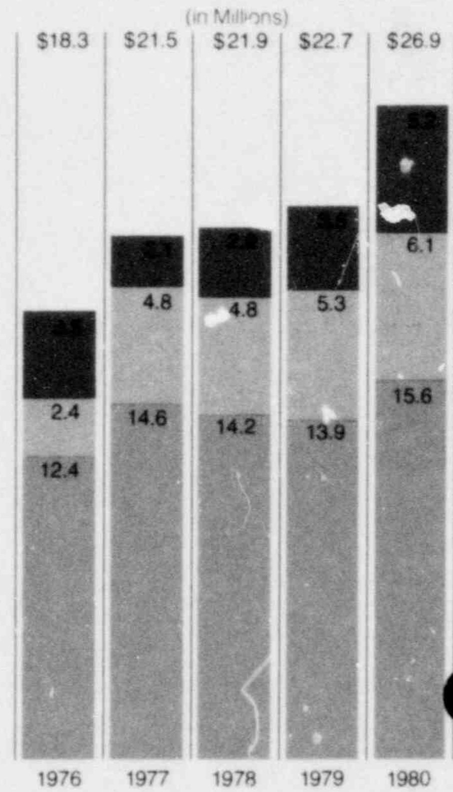
Earnings and Dividends

Earnings
Dividends



Revenues

Electric Retail
Gas
Electric Wholesale
Steam and Other



Net Income

Electric
Gas
Other

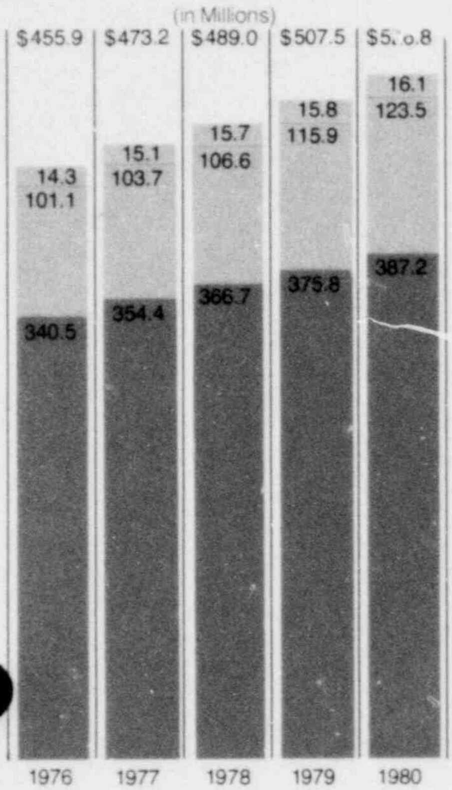
System Profile

New England Gas and Electric Association 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, two real estate trusts, an oil and gas exploration company, and a subsidiary involved in the manufacture and sale of gas-fired heating equipment. The Association also has a 34.5% ownership interest in a gas transmission and supply company and a 50% interest in a company engaged in the operation of an LNG facility serving our gas division. The electric subsidiaries receive capacity and energy from their respective ownership interests in one oil-fired and four nuclear electric generating facilities.

The Association is a business trust organized in 1926 under the laws of Massachusetts. Subsidiaries of the Association have common executive and financial management and receive technical assistance as well as data processing, accounting and other services from a service company subsidiary.

Financial Highlights



Plant

Electric
Gas
Steam and Other

	1980	1979	1978
Financial Statistics			
Total Operating Revenues	$512,535,000	$386,843,000	$339,195,000
Total Operating Expenses	477,435,000	356,591,000	309,165,000
Net Income	26,925,000	22,715,000	21,868,000
Earnings Applicable to Common Shares	22,892,000	18,622,000	17,714,000
Property Plant and Equipment (including Work in Progress)	561,768,000	531,745,000	506,455,000
Construction Expenditures	35,320,000	30,759,000	23,589,000
Common Stock Data			
Earnings Per Common Share	$3.01	$2.50	$2.40
Common Share Dividend Rate at End of Year	$1.72	$1.60	$1.52
Weighted Average Common Shares Outstanding	7,604,290	7,456,489	7,384,283
Common Shareholders	26,127	26,877	27,422
Operating Statistics			
Customers Served			
Electric (including seasonal)	267,900	260,900	256,100
Gas	194,600	189,700	185,800
Unit Sales (in thousands)			
KWH			
Retail	3,121,583	3,048,612	2,974,570
Wholesale	2,418,540	2,586,954	2,687,955
MCF	36,745	34,139	35,469

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Annual Meeting

All shareholders are invited to attend the next Annual Meeting which will be held on May 7, 1981. A formal notice of the meeting together with a proxy statement and a form of proxy will be mailed on April 3, 1981 to shareholders entitled to vote at the meeting

President's Letter

To Our Shareholders:

I am pleased to report that system operations improved significantly during 1980. Our earnings reached a record level of $3.01 per common share, compared to the $2.50 per share reported to you last year. This represents a 20% increase over 1979 results, a real accomplishment for a company in our industry. The improvement in earnings can be attributed, in part, to the rate relief granted to certain system subsidiaries, effective in January 1980 and from increased gas sales, in the wake of an extremely cold fourth quarter. Other major factors affecting 1980 results were a much higher level of other income from our equity earnings in Algonquin Energy, Inc. and interest income realized on short-term investments.

Although we are pleased by these operating results and the upswing in the economy of certain Massachusetts cities and towns in our service areas, the economic picture at the national level remains bleak. Prospects of continued periods of rising energy costs, high interest rates, unemployment and runaway inflation are of concern to us all. The unprecedented level of interest rates has been particularly disturbing. As you know, our industry is very capital-intensive, requiring significant amounts of capital to meet construction needs. The cost of completing new facilities needed for our electric and gas operations has grown dramatically in recent years. The threat which inflation poses to the financial stability of utilities and other businesses is of growing concern to us and to the financial community. This increased risk has caused utility financings to become more difficult and extremely expensive. Since these costs are ultimately reflected in our customers' bills, we continue to struggle with and seek solutions to this problem.

We strive to keep pace with the loss of real earnings and the erosion of the return on invested capital to maintain investor confidence. These efforts have included, among others, greater emphasis on cost control, requests for increased rates when necessary, and increases in our common dividend when justified by improved operating results. We were pleased to announce another dividend increase during 1980, to the current annual rate of $1.72 per common share. Providing an attractive return to our shareholders has been, and will continue to be, a prime objective of the Association's management.

As you know, the system's recent reorganization was, among other things, designed to streamline the management function and provide for increased and more responsive customer service. In conjunction with this consolidation and restructuring process, and as a result of changes in corporate activities, we have developed a one-system concept. In the past, our system has lacked a clear identity because we were a system of individual corporate entities and separate managements.

The Worcester/Cambridge Gas and New Bedford/Cape and Vineyard mergers of 1971 began the process of consolidation and simplification of our system activities. With the sale of New Bedford's gas assets to Commonwealth Gas accomplished, our new corporate identity program is entering its final stages. Further details on this program are provided in a separate section of this report. As communicated to you earlier, we will be seeking your approval at the annual meeting to change the parent name to "Commonwealth Energy System". When in place, we feel the new form of organization will help us to meet the challenges of the 80's.

The cost of fuel oil for our electric generating facilities has been increasing at an alarming rate. We began the year 1980 paying an average of $22 per barrel for fuel oil and at this writing are paying nearly $33 per barrel, with every indication that the escalation in OPEC

pricing will continue. We have reached the point where the power cost adjustment portion of our customers' electric energy bills now exceeds the base cost of providing service. Although no one could envision the dramatic trend in fuel oil prices which has taken place during the past two years, we are reminded of the intolerable regulatory and intervenor delays which have prevented completion of new generating facilities which could have lessened our problem, including the first unit at Seabrook, New Hampshire, which, based on the original schedule, should have been generating electricity today. The New England region, and our system in particular, has a greater reliance upon foreign oil sources than most of the country and consequently, has borne a disproportionate share of the excessive costs. The planned nuclear electric generating facilities which were expected to provide a significant portion of the region's future generation have encountered numerous problems. We have seen the postponement or cancellation of several nuclear projects in our region for various reasons, principally regulatory delays, reduced load growth and financial difficulties. Although demand has not yet approached the levels of earlier industry estimates, we continue to face the problem of providing reliable service to meet a growing demand and to replace older oil-fired facilities.

The government mandated use of coal or high-technology fuels for new facilities and the conversion of existing oil-fired units to these sources is a laudable concept, but it has major problems.

The Department of Energy has a congressional mandate to produce a reduction in oil consumption of utilities by banning the use of oil in boilers determined to be capable of converting to alternate fuels. We agree that this desired goal is in the national interest. However, before these massive expenditures are ordered, every possible alternative should be pursued including: building new units, replacing boilers, which would extend the life of converted units or using a coal-oil slurry mixture as soon as this process is perfected. Also, before these expenditures are incurred, some solutions should be presented to the logistical problems of coal supply and the disposal of ash and other residues from burning coal. We will continue to work toward an economically sound solution which makes sense for our customers and shareholders. We will also vigorously oppose any requirement which does not make sense.

We can anticipate that, as energy costs continue to rise, alternative sources will become more attractive and technological advances will eventually emerge. For the present, we view conservation efforts and load management as essential to the maintenance of an adequate reserve margin. These efforts will provide us with some of the energy required to meet increasing consumption, until such time as new facilities become operational.

The health and survival of our region and our nation is dependent on a workable national energy policy. The recent deregulation of domestic oil and gas prices has stimulated exploration and production activity and we are encouraged by indications that additional domestic energy supplies will become available in the future. Expansion of our domestic gas supply has been an early benefit of this action, although these new supplies will be delivered at a much higher cost. As stated in my message last year, the gas industry is beginning to receive recognition as having a major role in the nation's energy future.

Recent actions at the Federal level will further expedite industry efforts to assume that role. This past year saw record drilling and exploration activities as a result of the Natural Gas Policy Act. The congressional veto of the second phase of the incremental pricing provisions was a major victory for the gas industry.

Algonquin Energy, Inc. (34.5% owned by the Association) has become involved in expanded exploration activity, including the currently active "Western Overthrust Belt". In addition, they have recently finalized an agreement, subject to governmental approvals, to import natural gas from Canada. After these approvals have been received, it is contemplated that a new pipeline will be constructed. The pipeline will extend from northern Maine to Rhode Island, where it will connect with Algonquin's existing system.

These activities should not only provide our customers with new gas supplies, but also our shareholders with a higher return on investment.

We continue the search for sensible regulation of our businesses. The financial stability of our industry and the ability to serve customers in an adequate, cost-effective manner, must be addressed by regulators through the granting of fair and reasonable rates of return on a timely basis.

Management will continue its efforts to hold its costs down, however, one obvious point must be made — the days of cheap energy are past.

We continue to receive the strong support of you, our shareholders and our dedicated employees, and I am confident that, with your continued help, solutions to our problems can be found.

For the Trustees,

G. E. Anderson

G. E. Anderson,
President

Corporate Identity Program

We have recently completed the last major step in the implementation of our plan of organization which was adopted in 1978. All of our gas operations are now within one corporate entity — Commonwealth Gas Company. This was accomplished by the sale of our New Bedford company's gas assets to Commonwealth Gas in a transaction approved by the Massachusetts Department of Public Utilities (DPU) effective January 1, 1981.

This is a significant accomplishment since it aligns our corporate structure with the line of business organization we have used operationally for two years. This form of organization has many advantages. It gives each of our operating units the flexibility needed to deal effectively with the problems and concerns in their respective business environments. At the same time, we achieve a high degree of efficiency by centralizing those functions which are needed in support of all of our business activities.

As an adjunct to the organizational realignment, we are adopting a new system-wide corporate identity. We have selected the name Commonwealth Energy System for use by the parent organization and will link all of our subsidiaries through use of the Commonwealth name.

Our planning in this area is complete and we have recently begun to make some of the changes contemplated. The name of our New Bedford company was officially changed to Commonwealth Electric Company on March 1. We have also adopted new logos for use throughout our electric and gas service areas. In the next few months we will be making a major systematic effort to introduce our new image to the public.

Before we take the final steps in this process, at our Annual Shareholders' Meeting in May, we will ask for approval to change the name New England Gas and Electric Association to Commonwealth Energy System. Approval of this change is extremely important in furtherance of the one-system concept we are striving to achieve. We hope that you, our shareholders, share our enthusiasm for all aspects of this program and will give us your support.

In the section which follows, we have grouped our subsidiary companies under their new banners by operating division and have presented their new names in comparison to those in effect as we began this process.

COM/Energy

New England Gas and Electric Association	Commonwealth Energy System
NEGEA Service Corporation	Com/Energy Services Company
NEGEA Realty Trust	Com/Energy Realty Trust
NEGEA Energy Products, Inc.	Com/Energy Products Company
NEGEA Energy Services, Inc.	Com/Energy Exploration Company
Cambridge Steam Corporation	Com/Energy Steam Company
Darvel Realty Trust	Darvel Realty Trust

COM/Electric

New Bedford Gas and Edison Light Company	Commonwealth Electric Company
Cambridge Electric Light Company	Cambridge Electric Light Company
Canal Electric Company	Canal Electric Company

COM/Gas

Commonwealth Gas Company	Commonwealth Gas Company

Year in Review

Construction and Financing

Construction expenditures by the system during 1980 totaled $35,300,000, of which approximately $5,200,000 related to nuclear electric generating facilities in which the system is a joint-owner. Expenditures for 1981 will be approximately $79,000,000 and for the five-year period 1981-1985 more than $300 million. In addition to substantial expenditures relating to joint-owned generating facilities, these amounts also include costs related to electric transmission and distribution facilities and the expansion of our gas distribution system. Nearly 85% of the five-year total relates to electric operations, of which $114 million is for the system's interests in the construction of three nuclear generating facilities. An additional $8.8 million will be spent on these projects through 1987. A more detailed discussion of these projects is included in the Electric Division section of this report.

Although the system has financed a large portion of its construction through internally generated funds in recent years, during 1980 we had to utilize a greater amount of bank borrowings for this purpose.

There were no public offerings of securities by system companies during the year. The Association did, however, receive more than $2.6 million in proceeds from common shares issued through the Dividend Reinvestment and Common Share Purchase Plan.

Permanent financing plans for 1981 are limited to Commonwealth Gas Company's proposed issue of First Mortgage Bonds, probably during the latter part of the year. Based on our five-year plan, 60% of our construction requirements will come from internally generated funds, the remaining 40% from outside sources. During this period, our operating subsidiaries will issue long-term debt totaling $116,000,000 with the parent Association scheduled to sell common shares and long-term debt totaling $47,000,000. Our dividend reinvestment plan is expected to provide an additional $17.5 million in new equity funds during the same period.

Load Management/Conservation

Recent sharp increases in energy costs require that we expand and improve the management and use of energy production facilities. Some efforts have been the result of requirements mandated by legislative actions. In addition to the fuel cost problem, a second major factor — tremendous increases in the cost of constructing and maintaining energy producing facilities — has made improved management of these facilities a necessity. We are expanding our efforts and are researching various techniques and procedures which will result in a comprehensive and effective load management program. Time-of-use rates and new rate structures will be one product of this effort.

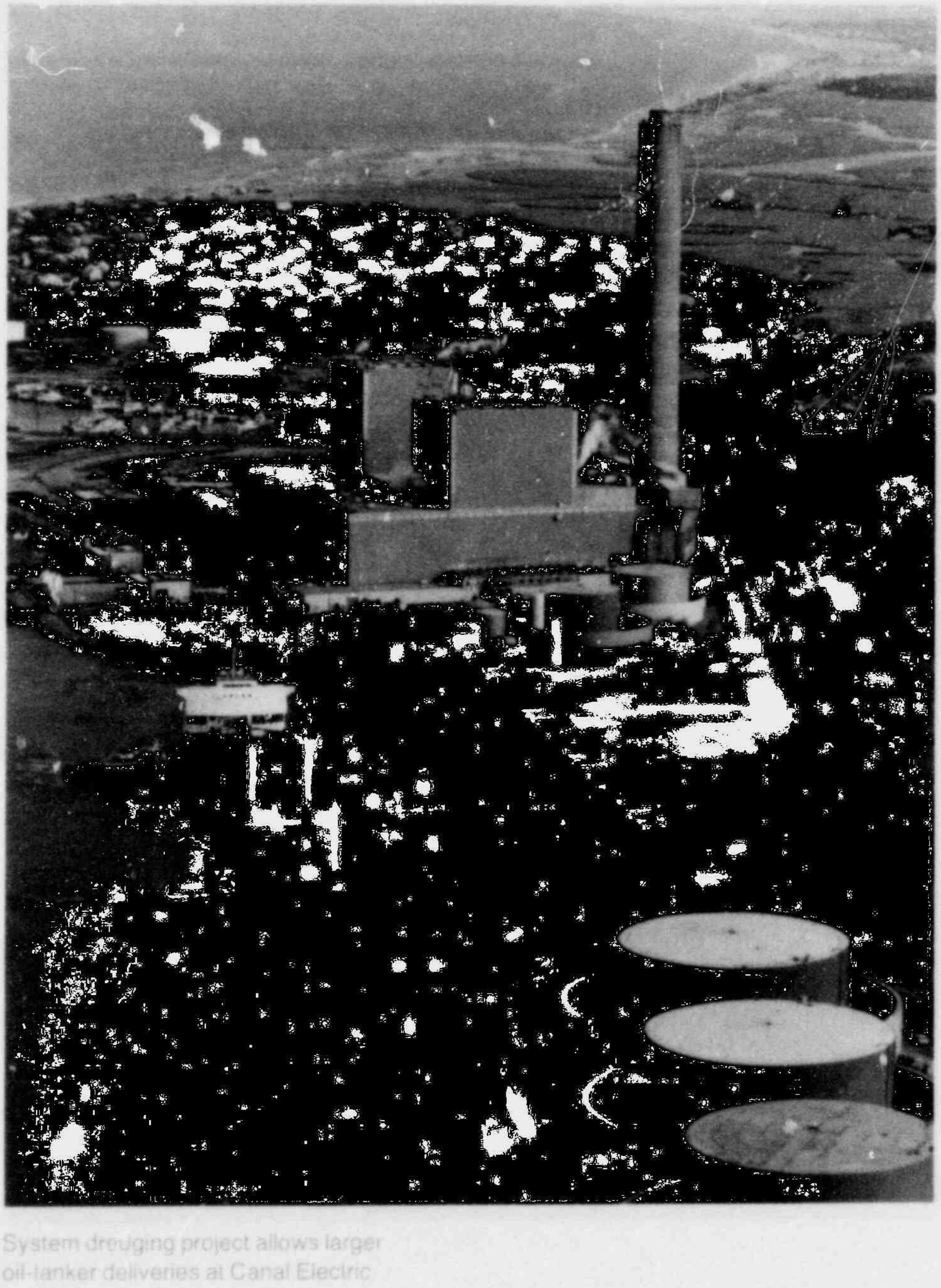
Activities to encourage and assist consumers with their conservation efforts have also been expanded. During 1980, a group of Massachusetts utility companies formed a non-profit corporation known as Mass-Save, Inc. Three of our companies, Commonwealth Electric, Cambridge Electric and Commonwealth Gas are members of this corporation.

Mass-Save, Inc. was established to furnish home energy audits to residential customers of member utilities. The audits will be provided at minimal cost and are designed to provide customers with information regarding energy use in their homes. Results of the audits will include recommended conservation measures together with estimates of installation costs and potential energy savings. The extra costs of the program will be recovered from all customers by a DPU approved residential conservation surcharge.

Rate Matters

Cambridge Electric Light Company filed a petition for increased rates with the DPU in November 1980. The purpose of this filing was to recover a $1.1 million increase in property taxes which had not been allowed in our last general rate case in early 1980. A decision by the DPU is expected in the very near future.

The DPU has historically been conservative in nature, choosing in most instances to adhere to the time-



System dredging project allows larger oil-tanker deliveries at Canal Electric Station.

honored concepts of rate design. During the term of the present Commission, however, there have been a number of positive developments which indicate a shift in this position. Massachusetts has now adopted the use of a year-end rather than an average rate base. In making this decision two of the three commissioners cited the need for the adoption of a "forward looking" test period. Also, the Commission in a recent proceeding, accepted as an adjustment to cost of service, an inflation allowance. Recognition of this allowance lessens the impact of inflation on utility company earnings.

Although Massachusetts is making positive strides in improving the regulatory environment, we are still being out-distanced by the progress made in some other states. Of major importance to our system companies and other Massachusetts utilities is the issue of construction work in progress in rate base. To date the Commission has steadfastly refused to address this issue in any fashion; and without consideration of this cost element in the determination of rates, we face the almost impossible task of actually earning the rates of return allowed by the regulatory process.

Changes in Board of Trustees

The announced retirement of two long-time and valued members of the Board of Trustees, effective May 7, 1981, has led to the nomination of two new individuals to fill these positions. One is Mr. Haynes H. Fellows, Jr., Vice President-Finance, Comptroller and Director of New England Telephone & Telegraph Company and the other is Mr. Sinclair Weeks, Jr., President and Chief Executive Officer of Reed & Barton Corp.

Electric Division

The management and trustees of the Association wish to thank the two retiring members, Mr. Burdette A. Johnson and Mr. Ora C. Roehl for their significant and valued contributions to our operations over these many years.

Burdette has been a member of our organization for more than 43 years in his capacity as employee and officer of the system and most recently having served nine years as a Trustee of the Association. His warm, spirited dedication to the community and his associates has endeared him to his legion of friends.

Ora has been a dedicated and active member of the Board of Trustees since 1962 and has served as Chairman of the Audit Committee from its inception in 1973. His intelligent, capable efforts on behalf of the Board have made a significant contribution.

We have been fortunate to have these two dedicated gentlemen associated with our organization. Their efforts have long been recognized and appreciated and we extend our best wishes to them for continued good health and success in the future.

1980 Results

Unit sales to retail electric customers for 1980 were 2.4% higher than the preceding year. This increase reflects customer growth somewhat offset by continued conservation efforts. 1980 was significantly colder than last year, yet average customer use remained relatively unchanged.

Operating revenues, on the other hand, increased by more than 30%. Increases in fuel-oil prices, which are recovered through power cost charges, have been primarily responsible for this rise in revenues. We experienced a 44% increase in fuel and purchased power costs, again, substantially the result of fuel-oil prices which rose from approximately $22 per barrel at the end of 1979 to almost $33 at the end of the year.

The rate increases granted to our Commonwealth Electric and Cambridge Electric subsidiaries were also major factors in both increased revenues and improved earnings. These increases totaled $7.7 million on an annual basis and were in effect for substantially all of 1980.

Peak Demand

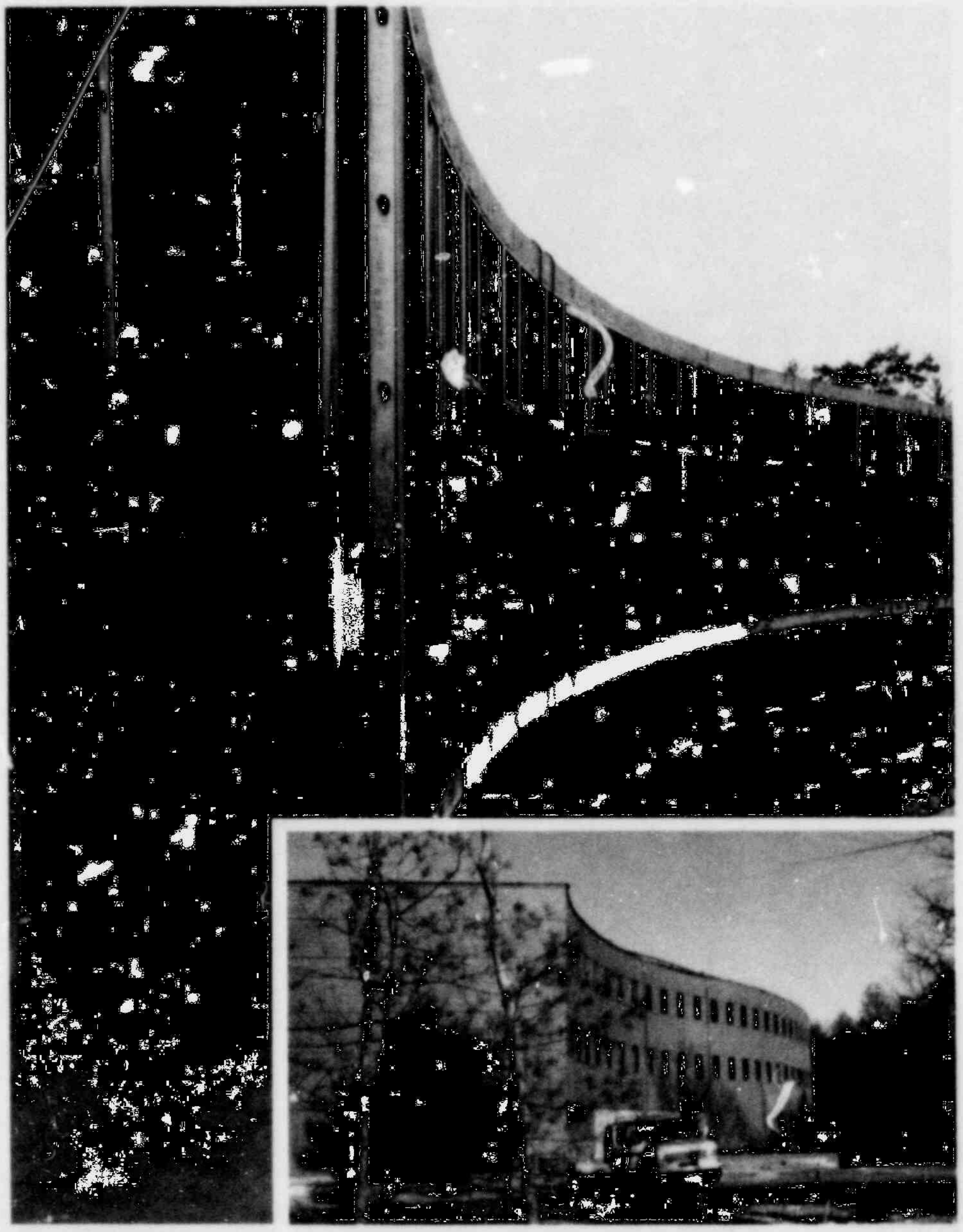
Despite the impact of high oil prices and inflation on our electric rates, we are continually faced with significant increases in demand during periods of extreme weather conditions. A very hot and humid period existed this past August, and as a result our system recorded an all-time record peak demand. The new peak of 648,000 kilowatts exceeded the previous peak of 633,000 kilowatts recorded less than one month earlier and represented a 4.3% increase over our 1979 peak, which compares to our current planning for peak load growth of only 2.5% annually.

During the cold weather this winter we again experienced significantly higher demands though not up to the level of last August. However, the New England Power Pool, which coordinates power distribution in the region, did experience a record demand during this winter.

Providing reliable capacity to meet our customers' demands has been a major commitment of our system and our planning efforts in this area have proved realistic and accurate. Because this planning effort has become very complex and somewhat uncertain because of changes in traditional customer patterns, we recognize the necessity of intensifying our research efforts in this critical area and will endeavor to improve on existing methodologies and load forecasting techniques. We will also continue our efforts to encourage energy conservation by our customers which should assist us in the optimum and most economic use of our production equipment.

Nuclear Construction Activity

In last year's Annual Report, we reported that New England Power Company had announced the cancellation of plans to construct two nuclear electric generating units in Rhode Island. Canal Electric was a joint-owner in this project. During 1980, Canal filed an application with the Federal Energy Regulatory Commission (FERC) seeking to amortize and recover these expenditures. An order was received during December, granting authority to amortize the investment in this project over a three-year period. In conjunction with our next retail rate application, we will request authorization to include these costs, net of income taxes, as an element in the cost of service.



New Electric Division headquarters in Wareham nears completion.

In December, Northeast Utilities (NU) announced cancellation of its plans to construct two nuclear generating units in Montague, Massachusetts. These units, which were planned to begin operations during the late 1980's and early 1990's had been postponed indefinitely during 1978. Officials at NU noted that their studies indicated that the capacity from these units would not be needed during the period for which the project was planned. We were a joint-owner in this project with a commitment of 80 megawatts. We will seek DPU approval to amortize and recover these costs.

After a lengthy period of deliberation, the DPU has finally approved the acquistion by Commonwealth Electric of an additional 50 megawatt interest in the Seabrook plant from the lead participant — Public Service Company of New Hampshire (PSNH). The transfer period related to this acquisition began in February 1981. This application was originally filed with that agency back in 1978. In February 1981, the DPU also approved the purchase of an additional interest by the Massachusetts Municipal Wholesale Electric Company. Commonwealth Electric's total commitment in the project is now 3.52% or 80 megawatts.

Construction work on the Seabrook plant was halted for a ten-week period during the summer of 1980 as a result of an ironworkers' strike. In addition, the Public Utility Commission in New Hampshire ordered PSNH to reduce the level of construction activity until such time as all regulatory approvals for transfer of its interest were obtained. These events will in all likelihood lead to a delay in estimated completion dates. The lead participant has not, as yet, indicated the extent of this delay, however, a recent Public Service prospectus indicated that the estimated completion dates could change to 1984 for Unit #1 and 1986 for Unit #2.

System Efficiency Noted

Our system generating units have now been rated, collectively, number one in overall "heat rate" among [illegible] electric utilities by *Electric Light and Power* magazine for the third year in a row. According to the survey, published in the August 1980 issue, the system topped the list with a rating of 9,709 BTUs (British Thermal Units) per kilowatt hour.

Our system's largest generating facility, the super-efficient Canal Electric units, operated by highly-skilled personnel, produced these excellent results. Careful attention to operating elements and adherence to a strict maintenance schedule are the combination of ingredients that have kept Canal Unit No. 1 at or near the top of the efficiency list since the early 1970's.

Wareham Headquarters Near Completion

Our new electric operations headquarters in southeastern Massachusetts is nearing completion and relocation of electric employees to this facility will begin during May. This group of some 300 employees is made up of system Electric Division personnel who are presently situated in several offices throughout our service territory. The new headquarters will contain offices for executive, administrative, customer service, energy supply, facilities development and human resources personnel. We believe that the consolidation of these operations in one location will enable us to provide the most efficient service to our customers at the lowest cost possible.

The building contains 76,000 square feet of office space and is situated on a 48-acre site in Wareham. Construction of the three-story, serpentine-shaped building, designed by architects Symmes, Maini & McKee, began in late March, 1980.

Canal Coal Conversion

We indicated in our last annual report that the Department of Energy (DOE) had surveyed many of the country's larger oil-burning electric generating facilities as required by the National Energy Act. The DOE was trying to determine which facilities could convert to an alternative fuel, thereby reducing the nation's dependence on oil.

Subsequent to this survey, the DOE met with system officials to discuss that agency's possible designation of our Canal Unit No. 1 as one which should be prohibited from burning oil. A notice of the DOE's intent was later posted in the *Federal Register*.

The possible requirement to convert Canal Unit No. 1, the most efficient oil-burning facility in the country, to a coal facility has been the subject of extensive study by system personnel. We have determined that such a conversion would cost in the range of $200 million to $300 million in today's dollars and would take up to seven years to complete. The financial, technical, operational and environmental difficulties were the subject of an extensive study which was presented to the DOE in October 1980, in opposition to the proposed order.

We have countered the DOE's plan with our own proposal to construct a new coal-fired facility. A new unit, built with current "state of the art" coal-burning equipment, would be, in our opinion, a wiser choice and would provide additional capacity for our customers' future needs.

At this time we have yet to receive a response from the DOE regarding either the study or the proposed new facility.

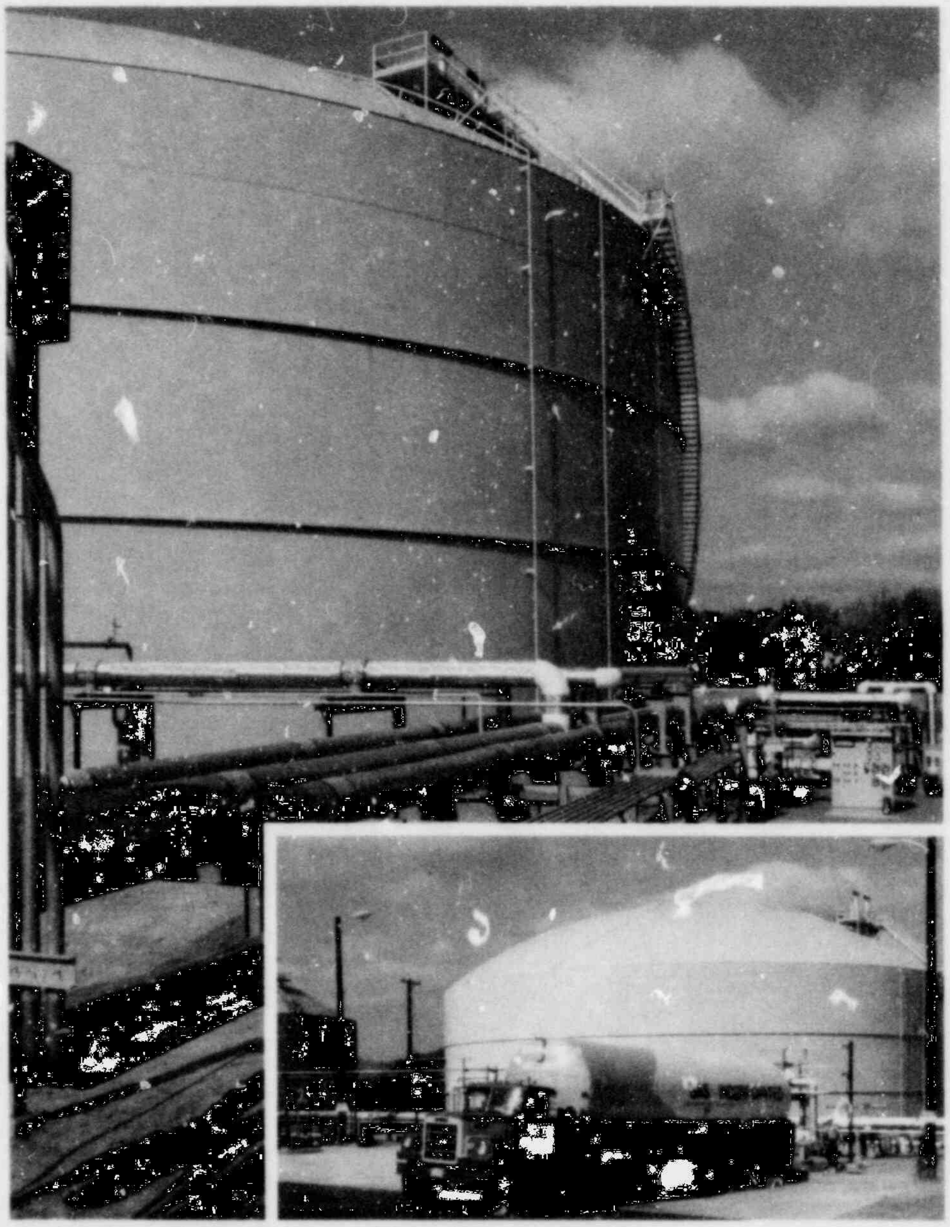
1980 Results

Results of gas operations for 1980 reflect a significant increase in unit sales, due in large measure to the extreme winter weather conditions of the fourth quarter. Added residential heating units were also a contributing factor. Unit sales increased 7.6% to nearly 37 million MCF. This increase compares to a 3.8% decrease in unit sales reported last year. Degree days for the period rose 9.1% compared to a 9.8% decrease in 1979.

Firm sales to residential customers increased 11.2% while other firm sales increased a total of 13.3%. These increases were substantially offset by declines in interruptible sales of 21.5%. This shift is the result of the increased demand for natural gas as a domestic energy source. Faced with seemingly endless fuel-oil price hikes and related supply problems, customers began turning to gas several years ago. During 1979, approximately 7,200 new residential heating units were added to the system. This year an additional 8,000 new units were added, including 850 new homes. We expect that with further reallocation of interruptible loads to firm customers and "conservation gas", an additional 3,900 new residential units will be added in 1981.

Gas Supply Emergency

Following the cold fourth quarter, the New England area began 1981 facing record cold temperatures and unprecedented demands for fuel to heat homes. Gas pipelines were delivering at capacity and supplemental sources were used to make up the difference. On January 9, a Massachusetts gas company declared a supply emergency. Two days later a special task force was formed, at the direction of the Governor, to oversee the critical supply situation and serve as a control center for the transferring of gas to the most



Hopkinton LNG storage tanks provide supplemental gas supply for system and emergency needs.

needy areas within the state. Commonwealth Gas Company's headquarters in Southboro was selected as the control center due to the strategic location of its facilities and our ability to assist others in need of gas supplies.

On January 13, a second gas utility announced its critical supply situation and the Governor repeated an earlier plea for statewide conservation. When this action failed to produce significant savings, gas-heated schools throughout the state were closed for several days and mandatory conservation measures were announced. During this period, Commonwealth was able to provide other companies with up to 95 million cubic feet of gas per day by utilizing its substantial LNG reserves in Hopkinton, Massachusetts.

During the crisis, which lasted until January 25, sendout records were established several times with a new peak of 284.8 million cubic feet being set on January 4. Throughout this period our gas supplies remained adequate and at no time were our gas operations personnel unable to meet our customers' needs.

This situation should serve as a warning to the residents of Massachusetts and New England. With the exception of nuclear generating plants, our region has virtually no natural energy resources; moreover, most of the resources we require are distantly located. And yet, efforts to site new energy producing facilities in the area invariably meet stiff opposition from regulators and environmentalists. Many projects either never get started or are terminated at an early stage. Lack of adequate pipeline capacity, storage facilities, and liquefaction and vaporization capability in our region force us to rely on distant supply facilities often

Diversified Operations

located a thousand miles or more from New England. This causes greater reliance on distant and frequently uncontrollable transportation and distribution facilities, impacting every energy consumer. Several of the reasons given for the problems encountered this winter were the very shortcomings just noted. In this light, it is interesting to note that when the first large-scale LNG tanker sailed into Boston Harbor, it was met with waves of protest. However, it was quite a different setting this past winter when, faced with further school and business shut-downs, the LNG tankers were welcomed with open arms.

Consolidation of Gas Operations

During 1980, a joint petition was filed with the DPU by New Bedford Gas and Edison Light Company and Commonwealth Gas Company for approval of the sale of New Bedford's gas assets to Commonwealth Gas. The DPU granted approval of this transaction effective January 1, 1981. System gas operations are now combined in one company, enabling us to more effectively utilize system personnel, equipment and energy supplies. In addition to the enhanced flexibility in allocation of natural gas, LNG and SNG supplies, there are potential advantages in dispatching and customer services.

The Marketing Future

In light of our marketing emphasis last year and given this winter's scenario, it may seem unusual for gas companies to continue to promote conversions from oil to natural gas for heating. However, when this winter's problem is analyzed, it turns out that the shortage was more of a delivery problem than one of supply. Such events are not unusual nor will this be the last. In the past we have experienced shortfalls of both fuel-oil and coal for domestic use because of transportation, strikes and other logistical problems.

Natural gas supplies in the United States are plentiful, with every indication that they will increase due to the surge in exploration activity prompted by deregulation. As mentioned earlier, Commonwealth Gas is planning to add approximately 3,900 new residential heating customers this year. Our research, marketing and supply personnel work very closely to determine how much gas is available to serve the firm market while maintaining an adequate "reserve" volume, which c[illegible] supplied to interruptible customers when available. Close working relationships with contractors and city and town officials also help to assure the most accurate load predictions. An example of how well those procedures work was the very favorable position enjoyed by Commonwealth Gas during this winter. The company has the advantage of two pipeline suppliers and LNG storage capacity equivalent to 3.5 billion cubic feet of natural gas. The combining of our gas operations into one corporate entity will enable us to more fully utilize these resources for the benefit of our customers. Also, the construction of the planned 11 mile, 12-inch gas main from Hopkinton to Worcester reinforced our supply capabilities to the Worcester area by making available an additional 20 million cubic feet of gas per day. This project was undertaken instead of attempting to secure additional rented storage space somewhere along our suppliers' pipelines, an approach, all variables considered, with many more risks. We continue to promote the use of gas for home heating based on the present price advantage over competitive fuels and with our optimistic domestic supply picture. Any reduction in our dependence on expensive foreign fuel-oil sources can only benefit our region and our country.

Realty Operations

In our 1979 Annual Report, we discussed a proposed office complex, which was to be constructed in Cambridge on land owned by Darvel Realty Trust.

The first phase of the project, to be known as Riverfront Office Park, will consist of an eighteen-story building which will overlook the Charles River and the Beacon Hill section of Boston. The building will have fourteen floors devoted to office space, three floors for parking and one floor for retail shopping activity. Darvel has formed a partnership with two other companies who together will share in the overall project costs and the operation of the facility with Darvel retaining title to the land.

While progress on this project to date has not reached our earlier expectations, we did see positive movement in 1980. A lead tenant has agreed to occupy several floors of the building and documents related to leasing and construction of the building have been drafted.

The present shortage of suitable office space in the greater Boston and Cambridge areas has driven rental prices higher and has significantly influenced the demand for space. The plans for progress and development of this area of Cambridge are encouraging for both us and the City of Cambridge.

The NEGEA Realty office building which is also in Cambridge, has benefited from the high demand for space. This building, which is partially occupied by system personnel, is presently fully occupied.

Manufacturing Operations

During 1980 NEGEA Energy Products continued to attempt to gain a share of a market dominated by firmly established domestic boiler manufac-

Commonwealth Gas load dispatch control center.

turers. Though unit sales increased in 1980, they were well below projected levels due in part to the excessive stocks of conventional boilers held by wholesalers during 1980 and the poor national economic climate, particularly as it related to both the new home as well as the retrofit market. We look for some improvement in 1981 as a result of our expanded marketing program and the introduction of a new electronic ignition model, which was recently certified by the American Gas Association.

Oil and Gas Exploration

We have determined that our system's future involvement in oil and gas exploration activity would be more appropriately conducted through our investment in Algonquin Energy, Inc. Algonquin has committed itself to a significant role in gas exploration and we are confident that their large-scale involvement can be very productive. We have therefore decided not to devote additional resources to this activity through NEGEA Energy Services, Inc. and will attempt to dispose of our present partnership interest in the Minuteman Exploration Company.

Algonquin Energy, Inc. is involved in a joint venture with Transcontinental Gas Pipe Line Corporation for the purpose of constructing a natural gas pipeline. The proposed pipeline would extend from Calais, Maine to Algonquin's present pipeline system in Rhode Island. This pipeline would be utilized to transport additional gas supplies from Canada. The construction cost, estimated at $500 million, would be equally shared by the two companies.

The companies have signed a gas supply contract with Pan-Alberta Gas Ltd. for the purchase of up to 306 million cubic feet of gas per day, one-half of which would be for use by Algonquin customers. The contract is for fifteen years and can be extended for an additional five-year period. Since the contract provides for possible gas storage in Canada, efforts are underway to develop a system which would provide additional daily quantities during the heating season.

Completion of the pipeline project and delivering of gas under the supply contract is contingent upon receipt of various governmental permits and approvals. The Canadian government has sought the necessary budget approval to authorize the completion of the required Canadian section of the pipeline. If the regulatory details are resolved both here and in Canada, and construction begins on a timely basis, the pipeline could be in operation during 1984.

The New England States Pipeline, as the project is known, when completed would allow the northeastern states to reduce their imported oil consumption by about 52,000 barrels per day, which is equivalent to 19 million barrels per year.

A hearing by the National Energy Board in Canada began in March 1981 on the first phase of their pipeline extension with further action taking place at the successful conclusion of those proceedings.

Financial and Statistical Information

Management's Report

The financial statements presented herein are representations of the management of New England Gas and Electric Association. 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 insuring that both the independent auditors and management fulfill their respective responsibilities as they pertain to these financial statements.

E. G. Cheney

E. G. Cheney,
Financial Vice President

February 17, 1981

Report of Independent Public Accountants

To the Board of Trustees of
New England Gas and
Electric Association:

We have examined the consolidated balance sheets and statements of capitalization of NEW ENGLAND GAS AND ELECTRIC ASSOCIATION (a Massachusetts trust) and its subsidiary companies as of December 31, 1980 and 1979, and the consolidated statements of income, changes in common shareholders' investment, redeemable preferred shares and sources of funds used for construction for each of the three years in the period ended December 31, 1980. 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 financial statements of Algonquin were examined by other auditors whose report thereon 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. The opinion of the other auditors was qualified; however, in our opinion, the Association has provided for the effect of the matter in its consolidated financial statements (see Note 4).

In our opinion, based upon our examination and the report of other auditors, the financial statements referred to above present fairly the financial position of the Association and its subsidiary companies as of December 31, 1980 and 1979, 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, 1980, in conformity with generally accepted accounting principles applied on a consistent basis.

ARTHUR ANDERSEN & CO.

Boston, Massachusetts,
February 17, 1981

Consolidated Statements of Income

Years Ended December 31,	1980	1979	1978
		(Dollars in Thousands)	
Operating Revenues:			
Electric	$326,050	$250,410	$214,551
Gas	169,807	124,563	115,704
Steam and other	16,678	11,870	8,940
	512,535	386,843	339,195
Operating Expenses:			
Fuel used in electric production, principally oil	187,743	130,709	90,752
Electricity purchased for resale	19,565	13,439	19,067
Cost of gas sold	113,793	76,026	67,550
Other operation	73,582	65,504	58,895
Maintenance	21,702	16,422	15,505
Depreciation	17,172	16,721	16,119
Taxes—			
Local property	20,280	20,006	20,798
Income (Note 2)	20,150	14,706	17,822
Payroll and other	3,448	3,058	2,657
	477,435	356,591	309,165
Operating Income	35,100	30,252	30,030
Other Income:			
Equity in earnings of Algonquin Energy, Inc. (Note 4)	5,074	3,486	3,732
Allowance for equity funds used during construction	100	629	684
Other, net	3,923	3,055	2,074
	9,097	7,170	6,490
Income Before Interest Charges	44,197	37,422	36,520
Interest Charges:			
Long-term debt	14,004	14,203	14,294
Other interest charges	6,778	2,043	1,098
Allowance for borrowed funds used during construction	(3,510)	(1,539)	(740)
	17,272	14,707	14,652
Net Income	26,925	22,715	21,868
Dividends on preferred shares	4,033	4,093	4,154
Earnings Applicable to Common Shares	$ 22,892	$ 18,622	$ 17,714
Weighted Average Number of Common Shares Outstanding	7,604,290	7,456,489	7,384,283
Earnings Per Common Share	$3.01	$2.50	$2.40

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

New England Gas and Electric Association and Subsidiary Companies

Consolidated Statements of Sources of Funds Used for Construction

Years Ended December 31,	1980	1979	1978
		(Dollars in Thousands)	
Sources of Funds—			
Internal Sources			
From Operations—			
Net Income	$26,925	$22,715	$21,868
Items not requiring or (providing) funds:			
Depreciation	17,172	16,721	16,119
Deferred income taxes — long-term	6,898	304	5,152
Investment tax credits, net	1,729	1,795	1,175
Equity in earnings of joint ventures, reduced by cash dividends of $2,281,000 in 1980, $2,231,000 in 1979 and $2,047,000 in 1978	(4,861)	(2,187)	(2,512)
Allowance for equity funds used during construction	(100)	(629)	(684)
	47,763	43,719	41,118
Less—			
Payment of dividends	16,912	16,036	15,238
Retirement of long-term debt and preferred shares through sinking funds	5,527	4,249	4,410
Other	(280)	911	50
	22,159	21,196	19,698
Change in net current assets (exclusive of interim financing)—			
Cash and temporary cash investments	(21,690)	17,580	(2,290)
Accounts receivable and unbilled revenues	(42,869)	(7,338)	13,577
Income taxes, net	9,185	(19,978)	(10,530)
Accounts payable and other	45,053	(13,535)	2,136
	(10,321)	(23,271)	2,893
Net available from internal sources	15,283	(748)	24,313
External Sources			
Sale of common shares	2,645	1,428	952
Notes payable to banks, net	20,000	28,950	(2,360)
Sale of long-term debt	—	3,500	—
Long-term debt issues refunded	(2,709)	(3,000)	—
Net available from external sources	19,936	30,878	(1,408)
	$35,219	$30,130	$22,905
Funds Used for Construction--			
Electric	$25,424	$19,216	$18,254
Gas	9,377	10,936	4,569
Other	518	607	766
	35,319	30,759	23,589
Less — Allowance for equity funds used during construction	100	629	684
	$35,219	$30,130	$22,905

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

Consolidated Balance Sheets

December 31,	1980	1979
	(Dollars in Thousands)	
Assets		
Property, Plant and Equipment, at original cost:		
Electric	$387,210	$375,790
Gas	123,529	115,891
Other	16,131	15,867
	526,870	507,548
Less—Accumulated depreciation	160,654	147,068
	366,216	360,480
Construction work in progress (Note 5)	34,898	24,197
	401,114	384,677
Equity in Corporate Joint Ventures:		
Algonquin Energy, Inc. (34.5%)	34,535	31,021
Nuclear electric power companies (2.5% to 4.5%)	7,621	7,260
Hopkinton LNG Corp. (50%)	1,639	1,532
Other investments	788	854
	44,583	40,667
Current Assets:		
Cash	6,861	4,621
Temporary cash investments	26,900	7,450
Accounts receivable, less reserves of $1,975,000 in 1980 and $1,432,000 in 1979	57,223	37,437
Unbilled revenues	39,068	15,985
Inventories, at average cost—		
Electric production fuel oil	5,614	15,185
Liquefied natural gas	9,147	8,568
Materials and supplies	7,380	6,396
Prepaid income tax	4,486	1,519
Prepaid property taxes and other	11,717	10,994
	168,396	108,155
Deferred Charges	9,669	7,115
	$623,762	$540,614

December 31,	1980	1979
	(Dollars in Thousands)	

Capitalization and Liabilities

Capitalization (See separate statement):		
Common share investment	**$158,898**	$146,240
Redeemable preferred shares, less current sinking fund requirements	**45,840**	47,660
Long-term debt, less current sinking fund requirements and maturities	**173,764**	177,471
	378,502	371,371
Current Liabilities:		
Interim Financing—		
Notes payable to banks	**48,[illegible]50**	28,950
Maturing long-term debt	**—**	2,709
	48,950	31,659
Other Current Liabilities—		
Current sinking fund requirements	**5,511**	3,920
Accounts payable	**67,732**	34,697
Accrued taxes—		
Local property and other	**11,954**	10,716
Deferred income	**19,292**	7,140
Accrued interest	**3,680**	3,659
Dividends declared	**4,307**	4,017
Other	**6,788**	5,195
	119,264	69,344
	168,214	101,003
Deferred Credits and Other:		
Accumulated deferred income taxes	**58,065**	51,191
Unamortized investment tax credits	**16,899**	15,170
Other	**2,082**	1,879
	77,046	68,240
Commitments and Contingencies (Note 5)		
	$623,762	$540,614

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

Consolidated Statements of Capitalization

December 31,	1980	1979
	(Dollars in Thousands)	
Common Share Investment:		
Common shares, $4 par value—		
Authorized — 10,000,000 shares		
Outstanding — 7,694,501 in 1980 and 7,508,392 in 1979	$ 30,778	$ 30,034
Amounts paid in excess of par value	36,818	34,917
Retained earnings (Note 3)	91,302	81,289
Total common share investment	158,898	146,240
Redeemable Preferred Shares, Cumulative, $100 par value (Note 7):		
Series A, 4.80%	4,560	4,680
Series B, 8.10%	6,720	6,880
Series C, 7¾%	16,380	16,920
Series D, 9.80%	20,000	20,000
Less current sinking fund requirements	(1,820)	(820)
Total redeemable preferred shares	45,840	47,660
Long-Term Debt, including premiums (Note 6):		
Association Bonds, collateralized by common stock of utility operating subsidiaries, due—		
1980, 3⅝%	—	2,624
1987, 6⅜%	13,696	13,853
1988, 6⅞%	3,218	3,302
1996, 8⅞%	4,057	4,157
1999, 4.80%	3,600	3,780
Less current sinking fund requirements and maturities	(521)	(3,145)
Total Association long-term debt	24,050	24,571
Subsidiary companies' long-term debt:		
Mortgage Bonds due—		
1982, 4⅝%	3,199	3,301
1992, 8⅝%	6,500	6,750
1993, 9%	11,242	11,462
1994, 6¼%	2,078	2,233
1996, 7%	15,004	15,562
2006, 8.85%	35,016	35,017
Notes due—		
1980, 6%	—	85
1982, 10¼%	3,000	3,000
1984, 3%, 6⅝%	419	489
1986, 4½%	4,100	4,150
1987, 4.90%	2,695	2,730
1988, 3⅞%	3,469	3,513
1992, 5⅝%	8,740	8,745
1994, 6¼%	640	686
1995, 8⅛%	7,198	7,384
1997, 6⅛%	5,225	5,225
1997, 6¼%	5,243	5,251
1998, 8⅜%	17,207	17,515
2000, 10⅝%	13,519	13,826
2001, 9¾%	4,200	4,400
2002, 7¾%	4,190	4,240
Less current sinking fund requirements and maturities	(3,170)	(2,664)
Total subsidiary companies' long-term debt	149,714	152,900
Total long-term debt	173,764	177,471
Total capitalization	$378,502	$371,371

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

Consolidated Statements of Changes in Common Shareholders' Investment

Years Ended December 31, 1980, 1979 and 1978

	Shares	Par Value $4 Per Share	Amounts Paid in Excess of Par Value	Retained Earnings	Total
			(Dollars in Thousands)		
Balance December 31, 1977	7,354,174	$29,417	$33,154	$67,980	$130,551
Add (Deduct)—					
Net income	—	—	—	21,868	21,868
Sale of shares	58,551	234	718	—	952
Cash dividends declared—					
Common shares—					
$1.50 per share	—	—	—	(11,084)	(11,084)
Preferred shares	—	—	—	(4,154)	(4,154)
Balance December 31, 1978	7,412,725	29,651	33,872	74,610	138,133
Add (Deduct)—					
Net income	—	—	—	22,715	22,715
Sale of shares	95,667	383	1,045	—	1,428
Cash dividends declared—					
Common shares—					
$1.60 per share	—	—	—	(11,943)	(11,943)
Preferred shares	—	—	—	(4,093)	(4,093)
Balance December 31, 1979	7,508,392	30,034	34,917	81,289	146,240
Add (Deduct)—					
Net income	—	—	—	26,925	26,925
Sale of shares	186,109	744	1,901	—	2,645
Cash dividends declared—					
Common shares—					
$1.69 per share	—	—	—	(12,879)	(12,879)
Preferred shares	—	—	—	(4,033)	(4,033)
Balance December 31, 1980	7,694,501	$30,778	$36,818	$91,302	$158,898

Consolidated Statements of Changes in Redeemable Preferred Shares

Years Ended December 31, 1980, 1979 and 1978

	Authorized and Outstanding Cumulative Preferred Shares—$100 Par Value				
	Series A 4.80%	Series B 8.10%	Series C 7¾%	Series D 9.80%	Total Shares
Balance December 31, 1977	49,200	72,000	180,000	200,000	501,200
Less—Sinking fund redemptions	1,200	1,600	5,400	—	8,200
Balance December 31, 1978	48,000	70,400	174,600	200,000	493,000
Less—Sinking fund redemptions	1,200	1,600	5,400	—	8,200
Balance December 31, 1979	46,800	68,800	169,200	200,000	484,800
Less—Sinking fund redemptions	1,200	1,600	5,400	—	8,200
Balance December 31, 1980	45,600	67,200	163,800	200,000	476,600

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

Notes to Financial Statements

1. Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of the Association and all of its subsidiary companies. All significant intercompany accounts and transactions have been eliminated in consolidation. The Association and its operating companies are sometimes collectively referred to in this report as the "system".

Equity Method of Accounting

System companies use the equity method of accounting for investments in corporate joint ventures. Under this method the system records as income its 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 generating facilities located in New England.

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 at the end of 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 also is recorded in unbilled revenues at the end of 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. System composite depreciation rates, based on average depreciable property in service, were as follows:

	1980	1979	1978
Electric	3.61%	3.69%	3.66%
Gas	3.05	2.94	2.96
Steam	3.53	3.53	3.52

Allowance for Funds Used During Construction

System utility companies include as an element of the cost of construction of depreciable property an allowance for funds employed during periods when property is under construction. An amount equal to the allowance capitalized in the current period is reflected in the statements of income. Under applicable rate-making practices, property under construction is not included in rate base on which the utility companies are permitted to earn a return. Amounts so capitalized, while not currently providing funds, are included in rate base when property is placed in service, and these amounts are recoverable in revenues over the service life of the constructed property. The amount of the allowance recorded was at a weighted average rate of 17% in 1980, 12¼% in 1979 and 10% in 1978.

2. Income Taxes

The system files a consolidated Federal income tax return. For financial reporting purposes, the subsidiaries provide taxes on a separate return basis and the Association records the tax effects which result from including its taxable loss in the consolidated return.

The following is a summary of the consolidated provision for income taxes for the years ended December 31, 1980, 1979 and 1978:

	1980			1979			1978		
	Total	Federal	State	Total	Federal	State	Total	Federal	State
	(Dollars in Thousands)								
Currently payable	$(1,007)	$(1,658)	$ 651	$ 8,295	$ 6,704	$ 1,591	$16,959	$14,317	$ 2,642
Currently deferred	12,530	10,861	1,669	(688)	(562)	(126)	(5,464)	(4,619)	(845)
Long-term deferred	6,898	5,990	908	5,304	4,603	701	5,152	4,520	632
Investment tax credits, net	1,729	1,729	—	1,795	1,795	—	1,175	1,175	—
	$20,150	$16,922	$ 3,228	$14,706	$12,540	$ 2,166	$17,822	$15,393	$ 2,429

Income taxes are provided for the tax effects of timing differences other than certain construction related costs. Timing differences result from reporting income and expense for tax purposes in periods different from those used for financial reporting purposes. The deferred provision represents principally the tax effects arising from deducting depreciation for income tax purposes that currently exceeds the amounts provided in the accounts. The greater tax depreciation arises from the use of accelerated depreciation methods and shorter lives permitted by the Federal and state income tax laws.

The system's long-term deferred provision for income taxes results from the use of the following:

	1980	1979	1978
	(Dollars in Thousands)		
Accelerated depreciation for tax purposes	$4,860	$4,505	$4,995
Capitalized interest during construction	1,611	38	74
Other	427	761	83
Long-term deferred income tax provision	$6,898	$5,304	$5,152

The tax effects of unbilled revenue and other current timing differences are included in the current deferred provision and deferred income taxes. Investment tax credits are deferred and amortized over the life of the property giving rise to the credits.

Income taxes totaling approximately $2,037,000 at December 31, 1980 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 43% in 1980, 39% in 1979 and 45% in 1978 of income before such taxes. The following table reconciles the statutory Federal income tax rate to these percentages:

	1980	1979	1978
Statutory Federal income tax rate	46%	46%	48%
Decrease from statutory rate:			
Effect of dividend received deduction	(5)	(6)	(5)
State tax net of Federal tax benefit	4	3	3
Allowance for funds used during construction	—	(3)	(2)
Other, net	(2)	(1)	1
	43%	39%	45%

3. Dividend Restriction

At December 31, 1980 approximately $24,977,000 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 $32,157,000 representing the system's equity in undistributed earnings of corporate joint ventures.

4. Algonquin Energy, Inc.

The Association uses the equity method of accounting for its 34.5% investment in Algonquin Energy, Inc.

The Federal Energy Regulatory Commission has not yet issued a final order regarding a rate increase which was billed to customers during 1980, subject to refund. Algonquin has made no provision for the effect of the refund, if any, which might be required upon final disposition of this rate proceeding.

The opinion of Algonquin's auditors on its financial statements is qualified as being subject to the outcome of these proceedings.

The Association has provided a reserve against its share of Algonquin's earnings which it estimates may ultimately be required to be adjusted due to refunds. Accordingly, the Association believes that final disposition of this matter will have no material impact on its consolidated financial statements. Condensed consolidated financial information of Algonquin is as follows:

	1980	1979	1978
	(Dollars in Thousands)		
Operations			
As reported by Algonquin —			
Operating revenues	$506,763	$352,723	$307,211
Income before income taxes	33,590	18,471	18,156
Provisions for income taxes	16,35[illegible]	7,539	7,597
Net income	$ 17,235	$ 10,932	$ 10,559
As reported by the Association —			
Equity in Algonquin's net income	$ 5,950	$ 3,774	$ 3,645
Add (deduct) —			
Provision for rate refunds	(880)	—	—
Adjustment for restatement of previously reported earnings and other	4	(288)	87
Reported equity in earnings	$ 5,074	$ 3,486	$ 3,732
Financial Position			
As reported by Algonquin —			
Total assets	$255,974	$228,659	$213,937
Less —			
Long-term debt	48,156	56,337	67,697
Other liabilities and deferred credits	105,371	82,506	62,835
	153,527	138,843	130,532
Net assets	$102,447	$ 89,816	$ 83,405
As reported by the Association —			
Equity in Algonquin's net assets	$ 35,365	$ 31,004	$ 28,791
Add (deduct) —			
Reserve for rate refunds	(880)	—	—
Adjustment for restatement of previously reported earnings and other	50	17	305
Reported equity in net assets	$ 34,535	$ 31,021	$ 29,096

Financial statements of Algonquin are included in the Association's Annual Report on Form 10-K filed with the Securities and Exchange Commission.

5. Commitments and Contingencies

Construction

The system has made substantial commitments in connection with its construction program, including commitments to participate as a joint owner in nuclear generating projects planned or under construction by other New England utilities. Construction expenditures for the five years ending December 31, 1985 are estimated at $302,000,000.

Joint-Ownership Interest in Electric Generating Units

The system has made commitments to participate as a joint owner in two nuclear projects which are being constructed by other New England electric utilities. These projects will provide approximately 98,000 kilowatts of capacity for our system. Each participant includes its interest in the project in its plant accounts and provides its own financing. These units have experienced delays in both the planning and building phases of construction which has resulted in significantly increased costs. The Seabrook nuclear units have experienced particularly burdensome delays as a result of various legal, regulatory and other problems. As indicated in a recent prospectus issued by the lead participant, Public Service Company of New Hampshire (PSNH), that company has been experiencing difficulty in obtaining external financing for its share of the project and in maintaining cash flow adequate to fund its construction program and the costs of current business operations. These difficulties resulted in a delay in construction of the project and PSNH was obliged to reduce its share of the project. Regulatory approval was recently granted to other participants to purchase a portion of PSNH's interest and payments for these purchases have begun. Refer to the discussion of nuclear construction activit[illegible] page 7 for additional information pertaining to the system's joint-ownership interests.

The system was a joint owner in two additional nuclear projects which were cancelled by the lead participants. The cost for one project, cancelled in 1979 by New England Power Company, totaled $1,764,000 as of December 31, 1980. The Federal Energy Regulatory Commission has granted approval for the system to amortize this cost over a three-year period, beginning December 1, 1980.

In December 1980, Northeast Utilities (NU) announced the cancellation of its plans to construct two nuclear units, which were to be located in Montague, Massachusetts. The capacity from these units was not expected to be needed by NU during the time period for which they were planned. Expenditures by our system in this project totaled $1,698,000 as of December 31, 1980.

The system companies involved will seek regulatory approval for amortization of the Montague project and further will seek regulatory approval to recover all costs of both cancelled projects.

Coal Conversion

The Department of Energy (DOE) has developed a list of oil-fired electric generating facilities which may be required to cease burning oil. The system's Canal Unit No. 1 is included in that list. The system has presented its opposition to such a prohibition citing operating, engineering, environmental and financial consequences. No determination has been made as of December 31, 1980 by the DOE.

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 used for electric generation. 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.

6. 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. These unsecured borrowings are evidenced by 90-day notes which are renewable at maturity. The lines of credit with banks, against which these notes payable are applied, totaled $64,000,000 at December 31, 1980.

The terms of one bank credit line require a compensating balance of $800,000 or a fee if such balance is not maintained. Another line of credit requires that when the system is borrowing, it must maintain normal operating balances for cash demand and bank service charges. The remaining lines of credit do not require compensating balances.

The interest rate for a majority of the borrowings is based upon either a floating prime rate or a fixed prime rate.

Long-term Debt Maturities

Under terms of their various indentures, the Association 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, 1980 are as follows:

Year	Sinking Fund Payments: Association	Sinking Fund Payments: Subsidiaries	Maturing Debt Issues	Total
	(Dollars in Thousands)			
1981	$521	$3,170	$ —	$ 3,691
1982	523	3,424	6,100	10,047
1983	521	3,427	—	3,948
1984	523	3,377	97	3,997
1985	522	3,350	—	3,872

Under one mortgage bond indenture of a subsidiary, the annual sinking fund requirement of $350,000 may be met by payment, repurchase of bonds, or certification of an amount of property additions equal to 60% of bondable property (as that term is defined in the indenture). The subsidiary expects to certify additional bondable property in lieu of making sinking fund payments on these bonds.

7. Redeemable Preferred Shares

The Association'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 Association 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 Association 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 tables:

	Dividend Rate	Sinking Funds 1981-1985 Mandatory	Optional	Optional Redemption Call Prices
		(Dollars in Thousands)		
Series A	4.80%	$ 120	$ 120	$102
Series B	8.10%	$ 160	$ 160	$112 to $101
Series C	7.75%	$ 540	$ 540	$112 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 Association.

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 Association may not redeem any shares unless all shares of all preferred series are redeemed.

8. Pensions and Employees Benefits

The system has a noncontributory pension plan covering substantially all regular employees who have attained the age of 25. 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 $5,946,000 in 1980, $5,474,000 in 1979 and $3,735,000 in 1978. The increase in expense is primarily due to changes in the plan which provide improved benefits to employees and retired personnel.

A comparison of accumulated plan benefits and plan net assets for the system's benefit plan is presented below:

	January 1, 1980	1979
	(Dollars in Thousands)	
Actuarial present value of accumulated plan benefits:		
Vested	$56,546	$46,437
Nonvested	1,479	1,212
	$58,025	$47,649
Net assets available for benefits	$37,925	$30,812

The plan uses a "5 year average of actual over expected return method" to determine the value of the plan assets. Under this method, an expected investment return is determined each year, based on market value of the fund at the beginning of the year; contributions, benefit payments and expenses paid during the year; and the actuarial assumption as to the return on investment, which is 6%. This expected return is compared to actual investment return and any excess is recognized over a five-year period.

The System also 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 $1,584,000 in 1980, $1,416,000 in 1979 and $1,301,000 in 1978.

9. 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 customers located in Massachusetts and adjacent New England states. Other operations of the system include the operation of rental properties, manufacturing and distribution of gas-fired heating equipment and oil and gas exploration; all of which do not presently contribute significantly to 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 unconsoli-

dated corporate joint ventures which provide energy and services to system gas companies.

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 electric generating plant projects located in New England.

	1980	1979	1978
	(Dollars in Thousands)		
Revenues from Unaffiliated Customers:			
Electric	$326,050	$250,410	$214,551
Gas	169,807	124,563	115,704
Steam and other	16,678	11,870	8,940
Total	$512,535	$386,843	$339,195
Operating Income Before Income Taxes:			
Electric	$ 36,673	$ 30,695	$ 33,758
Gas	18,426	13,562	13,240
Steam and other	151	701	854
Total Consolidated Operating Income	$ 55,250	$ 44,958	$ 47,852
Identifiable Assets:			
Electric	$424,125	$362,171	$346,353
Gas	158,775	137,169	118,456
Steam and other	16,022	15,318	20,722
	598,922	514,658	485,531
Intercompany eliminations	(20,623)	(14,682)	(7,051)
Investment in corporate joint ventures	45,463	40,638	38,158
Total Consolidated Assets	$623,762	$540,614	$516,638
Depreciation Expense:			
Electric	$ 13,389	$ 13,308	$ 12,838
Gas	3,500	3,141	3,009
Steam and other	283	272	272
Total Consolidated Depreciation	$ 17,172	$ 16,721	$ 16,119

Additional segment information relating to property additions is shown in the Consolidated Statements of Sources of Funds Used for Construction.

10. 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 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.

Constant dollar amounts represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers. Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

The current cost of plant 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 opera-

tion 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 ratemaking procedures prescribed by the regulatory commission, only the historical cost of plant is recoverable in revenues as depreciation. Because the excess cost of plant stated in terms of constant dollars and current cost is not recoverable in rates, an adjustment 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. System companies do not have the opportunity to realize a gain on debt because they are limited to recovery only of the embedded cost of debt capital.

Statement of Income from Continuing Operations Adjusted for Changing Prices
For the Year Ended December 31, 1980

	Conventional Historical Cost	Constant Dollar Average 1980 Dollars	Current Cost Average 1980 Dollars
	(Dollars in Thousands)		
Operating revenues	$512,535	$512,535	$ 512,535
Fuel, purchased power and gas	321,101	321,101	321,101
Depreciation expense	17,172	35,630	44,305
Other operation and maintenance expense	95,284	95,284	95,284
Income and other taxes	43,878	43,878	43,878
Interest expense	17,272	17,272	17,272
Other income and deductions — net	(9,097)	(9,097)	(9,097)
	485,610	504,068	512,743
Income (loss) from continuing operations (excluding reduction to net recoverable cost)	$ 26,925	$ 8,467*	$ (208)
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 71,718
Adjustment to net recoverable cost		$(27,812)	9,27[illegible]
Effect of increase in general price level			(100,13[illegible]
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			(19,137)
Gain from decline in purchasing power of net amounts owed		33,147	33,147
Net		$ 5,335	$ 14,010

*Including the adjustment to net recoverable cost, the income (loss) from continuing operations on a constant dollar basis would have been ($19,345,000).

**At December 31, 1980, current cost of property, plant and equipment, net of accumulated depreciation was $886,008,000, while historical cost or net cost recoverable through depreciation was $401,114,000.

Five Year Comparison of Selected
Supplementary Financial Data Adjusted for Effects of Changing Prices
(In Thousands of Average 1980 Dollars)

	Year Ended December 31,				
	1980	1979	1978	1977	1976
	(Dollars in Thousands Except Per Share Amounts)				
Operating revenues:					
Actual	$512,535	$386,843	$339,195	$359,746	$324,277
Adjusted to average 1980 dollars	$512,535	$439,158	$428,420	$489,175	$469,393
Historical Cost Information Adjusted for General Inflation —					
Income from continuing operations (excluding adjustment to net recoverable cost)	$ 8,467	$ 7,716			
Income per common share (after dividend requirements on preferred stock)	$ .58	$ .48			
Net assets at year-end at net recoverable cost	$151,765	$156,886			
Current Cost Information —					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	$ (208)	$ (945)			
Income (loss) per common share (after dividend requirements on preferred stock)	$ (.56)	$ (.68)			
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost	$ 19,137	$ 29,717			
Net assets at year-end at net recoverable cost	$151,765	$156,886			
General Information —					
Gain from decline in purchasing power of net amounts owed	$ 33,147	$ 37,901			
Cash dividends declared per common share	$ 1.69	$ 1.82	$ 1.89	$ 1.93	$ 1.93
Market price per common share at year-end	$ 14.38	$ 15.30	$ 19.46	$ 23.54	$ 22.83
Average consumer price index	246.8	217.4	195.4	181.5	170.5

Selected Financial Data

	1980	1979	1978	1977	1976
	(In Thousands Except Common Share Data)				
Operating Revenues:					
Electric	$326,050	$250,410	$214,551	$234,486	$214,467
Gas	169,807	124,563	115,704	116,427	101,481
Steam and other	16,678	11,870	8,940	8,833	8,329
Total	$512,535	$386,843	$339,195	$359,746	$324,277
Net Income	$ 26,925	$ 22,715	$ 21,868	$ 21,459	$ 18,288
Common Share Data —					
Earnings per share	$ 3.01	$ 2.50	$ 2.40	$ 2.36	$ 2.15
Dividends declared per share	$ 1.69	$ 1.60	$ 1.50	$ 1.42	$ 1.33
Weighted average shares outstanding	7,604,290	7,456,489	7,384,283	7,329,319	7,077,766
Total Assets	$623,762	$540,614	$516,638	$515,593	$501,055
Long-Term Debt Outstanding	$177,455	$183,280	$185,213	$188,902	$193,320
Redeemable Preferred Share Investment	$ 47,660	$ 48,480	$ 49,300	$ 50,120	$ 50,400
Common Share Investment	$158,898	$146,240	$138,133	$130,551	$122,843

Management's 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 establishment of rates affecting retail electric and gas sales and wholesale electric sales. The Massachusetts commission has generally required historical test-year information to support a rate increase filing. As a result, revised rates are unlikely to cover future costs or permit the system's utility subsidiaries to earn the allowed return on invested capital. Current periods of high inflation will continue to create a need for more frequent rate filings unless there is a recognition of future costs in determining revenue requirements. A discussion of the impact of inflation upon the system's operations is included elsewhere in this report.

Results of Operations

Operating revenues for 1980 increased by $125.7 million or 32.5% over 1979 while earnings for the year were $3.01 per common share compared with $2.50. Revenues were significantly higher for several reasons: increased costs of fuel used in electric production, purchased power and natural gas supplies, increased retail sales to customers and the impact of rate increases received early in 1980 by two subsidiaries.

Fuel and purchased power costs averaged $.037 per kilowatt-hour as compared with $.025 per kilowatt-hour in the preceding year. Since some 70% of our system's electric energy comes from oil-fired generating units, the rise in oil prices is directly responsible for most of the increase in fuel and purchased power costs. Oil prices have risen from approximately $22 per barrel at the beginning of the year to nearly $33 per barrel at the end of 1980. Higher prices for natural gas due to increases by pipeline suppliers and greater costs for other supplemental gas supplies were a major factor in the increased cost of gas. Our average cost per MCF this year was $3.10, compared with $2.27 per MCF last year.

Other expenses of operations and maintenance increased by 16.3%. These higher costs reflect inflationary increases in material and labor costs and significantly higher maintenance costs for the system's generating units at Canal Electric. This added maintenance was due in part to the use of higher sulphur content fuel which, although it is lower priced and reduces fuel cost, causes added maintenance. In addition, a major dredging operation in the Cape Cod Canal contributed to this increase.

Other income was up in large part due to equity earnings, reflecting a substantial increase in Algonquin Energy, Inc.'s income. Interest income from temporary cash investments was greater because of higher interest rates in effect during 1980.

Interest on short-term notes payable was significantly higher due to greater amounts borrowed to finance construction activities and as a result of higher interest rates.

Capital Resources

At December 31, 1980, system companies had short-term notes payable outstanding totaling $49 million which were used to temporarily finance construction of new or replacement facilities. Interim and permanent financing is done on an individual company basis, with the parent Association providing, when available, a portion of the subsidiary companies' short-term financing needs through advances and by purchasing 100% of any new common equity issues. To the extent possible, the Association's retained earnings and equity capital raised through its dividend reinvestment plan provide a substantial portion of the funds necessary to purchase new subsidiary common equity. When required, the Association issues new equity and/or debt issues to supplement those funds.

The budgeted construction expenditures for the five-year period ended 1985 are projected at $302 million. Financing this program will require long-term debt issues by subsidiaries of $116 million and additional equity investments by the Association totaling $74 million, of which $64.5 million will be provided by new common equity and long-term debt issues and the balance from retained earnings and prior years' funds from the dividend reinvestment plan.

Liquidity

The system's ability to generate adequate cash to meet its needs results primarily from the sale of electric and gas energy to retail customers and the collection of accounts receivable from these customers. Additional

sources include periodic bank borrowings, dividends from equity investments, and the sale of common shares through a dividend reinvestment plan. Although the system is projecting significant capital requirements during the next five years for its construction program, internally generated funds are expected to provide approximately 60% of these funds with temporary bank borrowings making up the remaining 40%. In keeping with a conservative capital structure, short-term borrowings are, from time to time, permanently financed through debt and equity issues. A substantial part of the system's internally generated funds are provided through depreciation and tax deferrals.

The system's cash flow was negatively affected during 1980 by large increases in fuel oil and purchased power costs and cost of gas. The rise in these costs and an extremely cold winter caused significantly higher utility bills. There are indications that customers may respond to these unexpected increases through slower payment of amounts due.

Unaudited quarterly information pertaining to the results of operations for the years ended December 31, 1980 and 1979 is presented in the following tables:

	1980 by Quarter				1979 by Quarter			
	1st	2nd	3rd	4th	1st	2nd	3rd	4th
	(Dollars in Thousands Except Per Share Amounts)							
Operating Revenues	$151,703	$93,983	$111,606	$155,243	$105,650	$72,759	$96,709	$111,725
Operating Income	10,728	7,603	8,385	8,384	9,233	6,381	7,334	7,304
Income Before Interest Charges	15,024	9,061	9,906	10,206	12,513	7,968	8,097	8,844
Net Income	10,389	4,779	5,682	6,075	8,929	4,604	4,330	4,852
Earnings per Common Share*	1.24	.50	.61	.66	1.06	.48	.45	.51
Price of Common Shares — High	15¼	16¼	16¾	15¾	16	16½	16⅞	15⅞
Low	11¾	12⅝	13⅞	12½	15⅛	14⅛	15⅝	13½

*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 1980-1971

	1980	1979
Operations (Dollars in Thousands)		
Revenues	$512,535	$386,843
Operating expenses —		
Operations	394,683	285,678
Maintenance	21,702	16,422
Depreciation	17,172	16,721
Taxes	43,878	37,770
Total	477,435	356,591
Operating income	35,100	30,252
Other income	9,097	7,170
Total income	44,197	37,422
Interest expense	17,272	14,707
Net income	26,925	22,715
Preferred dividends	4,033	4,093
Earnings applicable to common shares	$ 22,892	$ 18,622
Sources of Consolidated Net Income —		
Electric	$ 15,550	$ 13,939
Gas	6,135	5,257
Steam and other	5,240	3,519
Total	$ 26,925	$ 22,715
Financial (Dollars in Thousands)		
Property, plant and equipment (including construction work in progress)	$561,768	$531,745
Accumulated depreciation	160,654	147,068
Capitalization —		
Long-term debt	$173,764	$177,471
Preferred shares	45,840	47,660
Common equity	158,898	146,240
Total	$378,502	$371,371
Statistics and Ratios		
Unit sales — (In Thousands) KWH	5,540,123	5,635,566
MCF	36,745	34,139
Capitalization ratios —		
Long-term debt	45.9%	47.8%
Preferred shares	12.1	12.8
Common equity	42.0	39.4
Total	100.0%	100.0%
Return on common equity	15.0%	13.1%
Common share dividend pay-out	56.3%	64.1%
Average price/earnings ratio	4.7	6.1
Data Per Common Share		
Earnings per share*	$ 3.01	$ 2.50
Dividends paid	1.66	1.58
Annual dividend rate at end of year	1.72	1.60
Book value	20.65	19.48
Common share price range —		
High	16¾	16⅞
Low	11¾	13½

*Based on the weighted average number of shares outstanding.

1978	1977	1976	1975	1974	1973	1972	1971
$339,195	$359,746	$324,277	$288,330	$269,049	$184,795	$157,642	$141,613
236,264	255,942	230,879	216,433	199,004	122,926	97,904	85,649
15,505	14,174	10,819	9,305	9,277	6,930	5,880	6,146
16,119	15,590	14,439	10,910	10,166	9,700	9,192	8,604
41,277	42,368	37,427	27,205	26,383	25,606	26,857	24,998
309,165	328,074	293,564	263,853	244,830	165,162	139,833	125,397
30,030	31,672	30,713	24,477	24,219	19,633	17,809	16,216
6,490	4,463	4,360	3,179	3,613	3,327	3,057	3,722
36,520	36,135	35,073	27,656	27,832	22,960	20,866	19,938
14,652	14,676	16,785	14,266	14,938	11,601	10,239	9,359
21,868	21,459	18,288	13,390	12,894	11,359	10,627	10,579
4,154	4,183	3,042	2,260	2,279	1,182	611	273
$ 17,714	$ 17,276	$ 15,246	$ 11,130	$ 10,615	$ 10,177	$ 10,016	$ 10,306
$ 14,165	$ 14,578	$ 12,376	$ 10,150	$ 6,520	$ 5,811	$ 6,283	$ 6,898
4,817	4,837	2,375	931	3,708	3,076	3,148	2,350
2,886	2,044	3,537	2,309	2,666	2,472	1,196	1,331
$ 21,868	$ 21,459	$ 18,288	$ 13,390	$ 12,894	$ 11,359	$ 10,627	$ 10,579
$506,455	$486,476	$467,729	$451,428	$419,952	$383,415	$347,411	$325,326
133,470	121,019	109,473	99,363	92,752	86,595	81,644	78,359
$180,056	$186,699	$190,532	$159,553	$151,438	$151,974	$128,457	$126,244
48,480	49,300	50,120	30,400	30,680	30,960	13,240	5,520
138,133	130,551	122,843	111,102	98,979	95,867	93,134	90,471
$366,669	$366,550	$363,495	$301,055	$281,097	$278,801	$234,831	$222,235
5,662,525	5,912,434	6,144,891	5,621,499	5,238,963	5,682,061	5,358,814	5,022,376
35,469	32,711	32,314	30,091	34,790	33,174	33,964	30,795
49.1%	50.9%	52.4%	53.0%	53.9%	54.5%	54.7%	56.8%
13.2	13.5	13.8	10.1	10.9	11.1	5.6	2.5
37.7	35.6	33.8	36.9	35.2	34.4	39.7	40.7
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
13.2%	13.6%	13.0%	10.6%	10.9%	10.8%	10.9%	11.6%
62.6%	60.3%	62.7%	76.4%	70.7%	73.1%	73.4%	69.6%
6.9	7.2	6.8	6.5	6.7	9.0	10.4	8.9
$ 2.40	$ 2.36	$ 2.15	$ 1.71	$ 1.77	$ 1.70	$ 1.67	$ 1.72
1.48	1.40	1.31	1.28	1.24	1.24	1.22	1.18
1.52	1.44	1.36	1.28	1.28	1.24	1.24	1.22
18.63	17.75	16.82	16.21	16.49	15.97	15.52	15.07
18⅛	18⅞	16⅜	13½	15⅜	18¼	19¾	20¾
15	15⅛	12¾	8⅞	8⅜	12½	15	10

Trustees and Officers

Trustees of New England Gas and Electric Association

The name "New England Gas and Electric Association" means the trustees for the time being (as trustees but not individually) under a Declaration of Trust dated December 31, 1926, as amended, which is hereby referred to, and a copy of which has been filed with the Secretary of The Commonwealth of Massachusetts. Any agreement, obligation or liability made, entered into or incurred by or on behalf of said Association binds only the trust estate, and no shareholder, director, trustee, officer or agent assumes, or shall be held to, any liability by reason thereof.

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 D. Heaton*
Vice President — Corporate Planning

John J. Molloy*
Vice President — Public Relations

J. James Tasillo, Jr.
Vice President — Rates

Walter J. Cotting
Assistant Vice President — Information Services

Robert S. Parker
Treasurer

Michael P. Sullivan
Secretary

John A. Whalen
Comptroller

Electric Division

Jeremiah V. Donovan*
Executive Vice President

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

Richard G. Velte
Vice President — Facilities Development

Gas Division

William G. Poist*
Executive Vice President

Donald Johnson
Vice President — Customer Services

James M. Meikle
Vice President — Administration

Harold A. Melden
Vice President — Gas Supply

Franklin J. Morrison
Vice President — Facilities Development

John R. Williams
Vice President — Human Resources

*Member of Policy Committee

Transfer Agents and Registrars

Common Shares
Transfer Agent and Registrar: The First National Bank of Boston

Preferred Shares — Series A, B, C
Transfer Agent: The Association
Registrar: State Street Bank and Trust Company

Preferred Shares — Series D
Transfer Agent: The First National Bank of Boston
Co-Transfer Agent: The Association
Registrar: State Street Bank and Trust Company

Dividend Payments

(Paid by the Association subject to declaration by Trustees)
Preferred on the 1st day of January, April, July, October
Common on the 1st day of February, May, August, November

Trustees Under Indentures of Trust

The First National Bank of Boston — The Association's Bonds
Citibank, N.A. — Canal Electric Company Series B Bonds
State Street Bank and Trust Company — Other Subsidiary Companies' Long-term Debt and the Association's Bond Sinking Funds

Listing Affiliations

Common
New York Stock Exchange, Inc.
Boston Stock Exchange
Pacific Stock Exchange, Incorporated

Preferred — Series D
New York Stock Exchange, Inc.

Form 10-K

The Association 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 1980 Annual Report. However, a copy of Form 10-K is available upon written request addressed to Michael P. Sullivan, Secretary, New England Gas and Electric Association, P. O. Box 190, Cambridge, Massachusetts 02139.

The sole purpose of this report is to give present security holders information about this Association and its subsidiary companies and it is not a representation, prospectus or circular in respect to any security of this Association or of its subsidiary companies.

System Facts

System Companies

Electric

Cambridge Electric Light Company
Canal Electric Company
Commonwealth Electric Company

Gas

Commonwealth Gas Company

Steam

Cambridge Steam Corporation

Other Companies

NEGEA Service Corporation
(service company)
NEGEA Realty Trust
(owns and operates office building in Cambridge with system companies as major tenants)
Darvel Realty Trust
(organized to own property within Massachusetts for partial occupancy by system companies)
NEGEA Energy Products, Inc.
(manufacture and sale of gas-fired heating equipment)
NEGEA Energy Services, Inc.
(oil and gas exploration)

In addition, the Association owns 34.5% of Algonquin Energy, Inc. whose subsidiaries are principal suppliers of natural gas and SNG to the system, and 50% of Hopkinton LNG Corp., an LNG service company.

The system has a 1.4% (8,000 KW) interest in a jointly-owned oil-fired generating unit and also owns from 2½ to 4½% interests in four joint venture nuclear power plant projects in New England (projects located in Massachusetts, Connecticut, Vermont and Maine) with power entitlements the same as ownership interest in each project. Aggregate power entitlement from these plants is 76,000 KW.

Territory of Utility Operating Companies

Electric Operations — 1,112 square miles covering 41 communities with population of 559,000.
Gas Operations — 1,012 square miles covering 47 cities and towns (including 12 served with electricity) with population of 1,031,000.

Customers

Electric — 267,900
(including 43,800 seasonal)
Gas — 194,600

Employees and Shareholders at Year-End

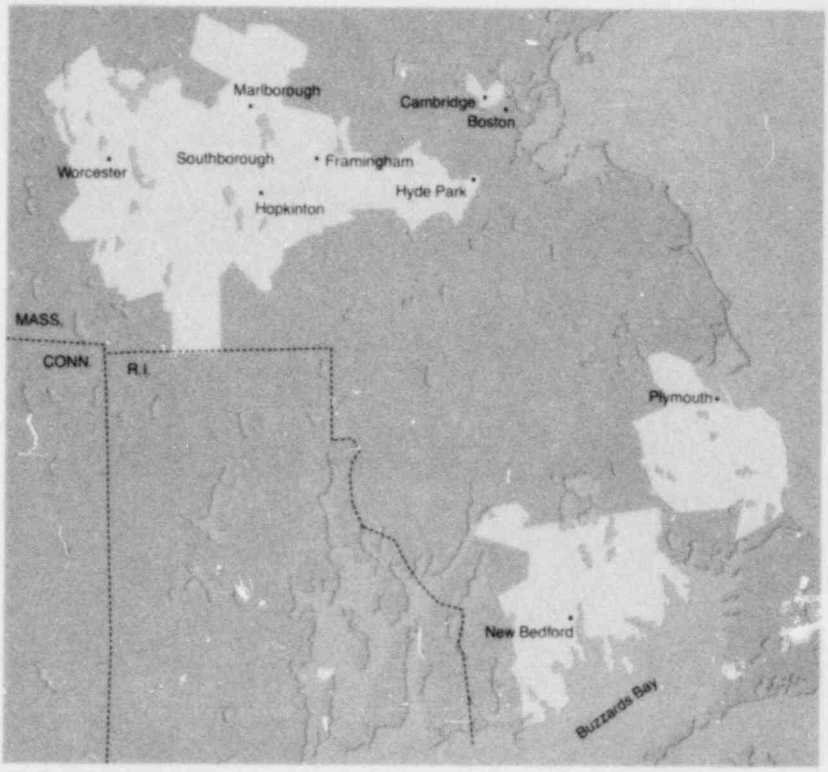
Employees — 2,413
Shareholders — 26,127

Electric Plant

Capability — 1,078,000 KW, including 864,000 KW for Canal Electric Company of which 426,000 KW is currently sold to other utilities.
Peak demand — 648,000 KW on August 6, 1980.

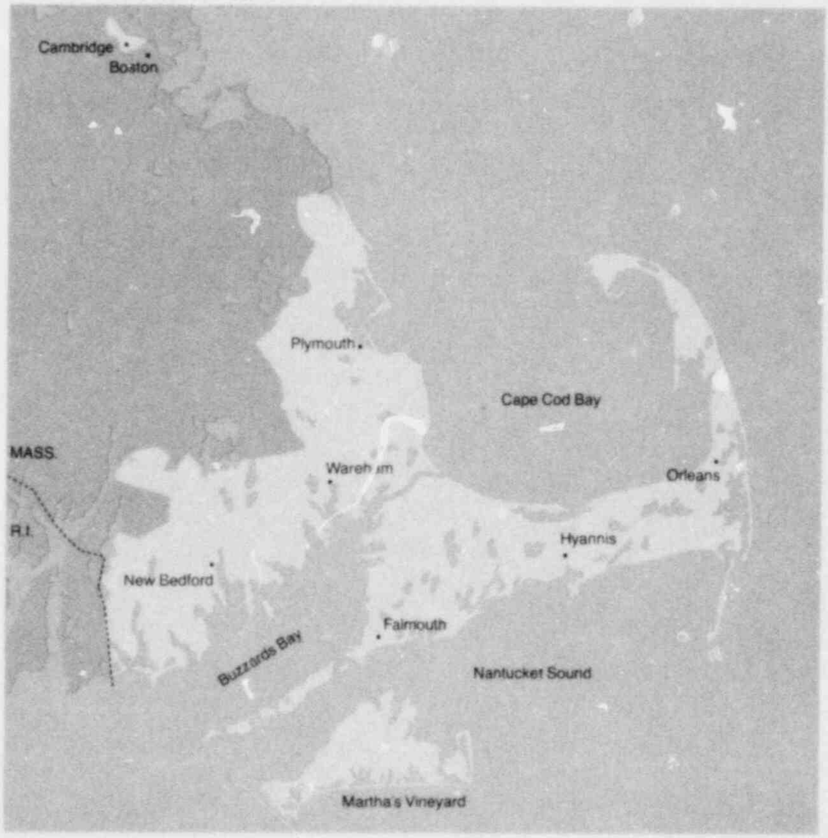
Gas Plant

Distribution lines — 2,320 miles
Peak day send-out — 284,800 MCF on January 4, 1981



Gas Service Area

Electric Service Area



New England Gas and Electric Association
An Investor-Owned Taxpaying Utility System
Post Office Box 190
Cambridge, Massachusetts 02139

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 December 31, 1980 Commission file number 2-30057

CANAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Massachusetts	04-1733577
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
675 Massachusetts Avenue, Cambridge, Massachusetts	02139
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code 617 - 864 - 3100

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

Title of each class	Name of each exchange on which registered
None	None

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

None
(Title of Class)

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, and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ____

Shares of common stock outstanding at March 16, 1981 1,523,200

The Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K as a wholly-owned subsidiary and is filing this Form with the reduced disclosure format.

Documents incorporated herein by reference - None

Exhibit index begins on page 27 of this report.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

PART I.

Item 1. Business

Canal Electric Company ("Company"), a wholly-owned subsidiary of New England Gas and Electric Association ("Association"), is a wholesale electric generating company organized in 1902 under the laws of the Commonwealth of Massachusetts. The Company assumed its present corporate name in 1966 after the sale to an affiliated company of its electric distribution and transmission properties together with the right to do business in the territories served.

The Company's generating station is located in Sandwich, Massachusetts at the eastern end of the Cape Cod Canal. The station consists of two oil-fired steam electric generating units: Canal Unit No. 1, with a rated capacity of 572 MW, is wholly-owned by Canal; and Canal Unit No. 2, with a rated capacity of 584 MW, is jointly-owned by Canal and Montaup Electric Company (a non-affiliated company). Canal Unit No. 2 is operated under an agreement with Montaup which provides for the equal sharing of output, costs and operating expenses.

Construction of Unit No. 1 was completed in 1968 and Unit No. 2 commenced commercial operation February 1, 1976. The Company expects to participate as a joint-owner of other generating units to be constructed by itself and other New England utilities.

By virtue of its charter which is unlimited in time, the Company generates and sells electricity at wholesale to other utilities without direct competition in kind from any privately or municipally-owned utility.

Power Contracts

The Company has entered into substantially identical life-of-the-unit power contracts with Boston Edison Company, Montaup Electric Company and New England Power Company (neighboring utilities), under each of which the customer is severally obligated to purchase one quarter of the capacity and energy of Unit No. 1, and with Commonwealth Electric Company ("Commonwealth Electric") and Cambridge Electric Light Company ("Cambridge Electric"), both distribution subsidiaries of the Association, under which the two are jointly obligated to purchase the remaining one quarter of the unit's capacity and energy.

A similar contract is in effect between the Company and Commonwealth Electric and Cambridge Electric, under which those companies are jointly obligated to purchase the Company's entire one-half share of the net capability of Unit No. 2.

The price of power under the power contracts is based on a two-part rate consisting of a demand rate and an energy rate. The demand rate covers all expenses except fuel costs and provides for a return on investment as well as recovery of investment over the economic lives of the units. The

Item 1. Business (Continued)

Power Contracts (Continued)

energy rate is based on the cost of fuel and is billed to each purchaser in proportion to its consumption of power. Purchasers are billed monthly. The power contracts are on file with the Federal Energy Regulatory Comm--sion (FERC).

New England Power Pool

The Company is a member of the New England Power Pool (NEPOOL), whose central dispatching facility (NEPEX) coordinates the operation essentially all of the generation and transmission facilities in New England. Under its long-range program, NEPOOL will enable member utilities to install fewer but larger, more efficient generating units and higher voltage transmission lines for the purpose of obtaining lower cost power and increased reliability.

Under NEPEX the most economically available generating units of member companies are operated to fill the demand for power in the entire region. In the past, this has required that Unit No. 1 operate whenever possible since it is one of the most efficient oil-fired units in the country. Unit No. 2 is designed for cycling operation which provides for economic changes in unit load. This design permits reduced generation during nights and weekends when demand in the region is lowest and it has performed as one of New England's most efficient units in this type of service.

The Company and the Association's other electric subsidiaries are also members of the Northeast Power Coordinating Council (NPCC), an advisory organization which establishes criteria and standards for reliability and serves as a vehicle for coordination in the planning and operations of these systems to enhance reliability.

Regulation

The Company is subject to regulation by the Massachusetts Department of Public Utilities (DPU) as to issue of securities, accounting, and other matters. The Company is a "public utility" within the meaning of Part II of the Federal Power Act and is subject to regulation thereunder by the FERC as to rates, accounting and other matters and has filed its power contracts with the FERC as rate schedules.

During 1979 the Department of Energy (DOE) began to survey existing electric generating stations which use oil as fuel in their boilers, as required under the Fuel Use section of the 1978 National Energy Act. The objective of this portion of the Act is to reduce the nation's overall dependence on oil by requiring conversion of existing units to alternative types of fuel. The DOE plan would prohibit the use of oil by those facilities which are deemed capable of converting to coal or an alternate fuel. In 1979, the Company's Unit No. 1 was initially surveyed by the DOE and during 1980 the DOE issued a proposed

Item 1. Business (Continued)

Regulation (Continued)

prohibition order barring the burning of oil in Unit No. 1. The possible requirement to convert Canal Unit No. 1 to a coal facility has been the subject of intensive study by Company personnel, who have determined that sucn a conversion would cost in the range of $200 million to $300 million in today's dollars and would take up to seven years to complete. The financial, technical, operational and environmental difficulties were the subject of an extensive study which was presented to the DOE in October 1980, in opposition to the proposed order.

The Company has countered the DOE's plan with a proposal to construct a new coal-fired facility.

At this time the Company has yet to receive a response from the DOE regarding either the study or the proposed new facility.

Fuel Supply

The Company is in the final stages of negotiation of a new long-term contract with Charter Oil (Massachusetts), Inc., for the purchase of the total estimated requirements of residual fuel oil for Unit No. 1 and Unit No. 2. During 1980 the Company has maintained an average daily inventory of approximately 485,000 barrels of fuel oil which represents 16 days of normal operation of the two units This supply is maintained by tanker deliveries approximately every five to ten days.

Future Generating Plant Commitments

The Company or Commonwealth Electric has made commitments to participate as a joint-owner in three nuclear units which are planned or under construction by members of NEPOOL. The Company plans to purchase Commonwealth Electric's interest in such units after both companies have obtained required regulatory approvals.

The total planned capacity for these units is approximately 3,450 MW. The Company's ultimate entitlement is 98 MW and is no greater than 5% with respect to any single unit, as shown in the table below

Unit (b)	Plant Capacity (MW)	System Entitlement (MW)	Location	Scheduled Completion Date	Estimated Cost of Entitlement	Expenditures through December 31, 1980	Estimated Cost Per (MW)
					(In Thousands)		
Seabrook Nos. 1 and 2	2 300	80(a)	Seabrook, NH	1983-1985	$109 604	$18 478	$1 370
Pilgrim No. 2	1 150	18(a)	Plymouth, MA	Not Determined		$ 6 661	$ -

Item 1. Business (Continued)

Future Generating Plant Commitments (Continued)

(a) Commitment of Commonwealth Electric to be acquired by the Company.

(b) The lead participants for the nuclear units described above are Public Service Co. of New Hampshire and Boston Edison Company, respectively.

The Company expects to construct or acquire additional generating capacity in the future in order to meet the load requirements of the distribution subsidiaries of the Association.

Construction and Financing

The Company has made substantial commitments in connection with its construction program. Estimated construction expenditures for the five-year period ending in 1985 are $157,300,000. Included in this amount is $25,100,000 representing Commonwealth Electric's cost as of December 31, 1980 of its investment in jointly-owned generating facilities which the Company proposes to purchase and approximately $114,000,000 representing amounts presently committed by Commonwealth Electric applicable to such facilities for the five-year period. The Company will also assume additional commitments for construction costs, related to participation in the jointly-owned plants, for years beyond 1985. These amounts are estimated at $8,800,000.

The estimated construction costs and completion dates for these projects have changed as a result of regulatory, financing, legal and other problems associated with construction of nuclear and other generating facilities. The Company is unable to predict what effect present or future construction difficulties related to these projects will have on its present construction estimates and the estimated completion dates.

The Company's construction program is subject to periodic review, and actual expenditures may vary from the above estimates because of factors such as changes in business conditions, rates of growth, effects of inflation, equipment delivery schedules, licensing delays, availability and cost of capital, and environmental factors.

During the construction period for the jointly-owned generating units each of the participating utility companies finances its own share of the individual units. When these units become operational, the lead participant acts as the operator and bills the participants for their proportionate share of the operating expenses and other costs associated with the unit. Estimated construction expenditures relating to the jointly-owned generating units are based upon the most recent information furnished by the utility responsible for the construction of each unit.

Item 1. Business (Continued)

Construction and Financing (Continued)

During the five-year period ending December 31, 1985, it is estimated that internally-generated funds will provide approximately $94,000,000 to be used for construction. The balance of the funds required will be provided on an interim basis by short-term borrowings which are expected to be replaced by long-term debt and equity securities.

Financings presently planned for the period ending December 31, 1985 consist of long-term debt issues totaling $40,000,000 and $25,000,000 from the sale of equity securities to the Association. The exact type, timing and amount of future long-term debt and equity financings are subject to change because of market conditions and other factors.

Environmental Matters

The Company's generating facilities are subject to Federal, state and local environmental quality control regulations. With respect to Unit No. 1 and Unit No. 2, these regulations have required capital expenditures by the Company of approximately $16,256,000. Environmental regulations also require the burning of 1.0% sulphur content oil. However, the Company received an exemption from these regulations during 1979 and is burning 2.2% sulphur content oil. The exemption is subject to periodic review the first of which is scheduled for no later than July 1, 1982.

Future compliance with existing regulations will require capital expenditures by the Company through 1985 of an estimated $20,600,000 including approximately $19,600,000 for the Company's proportionate share of such costs to be incurred in connection with construction of jointly-owned generating plants. These amounts have been included in the construction estimates discussed under "Construction and Financing".

Environmental regulations governing site selection for new electric generating facilities and imposing air and water pollution standards requiring the installation of costly pollution control facilities have had and may continue to have an effect upon the capital costs and construction schedules of NEPOOL generating facilities. The increases in cost cannot be predicted, since the standards and the technology required to meet them are in a state of rapid change. There has been particular public controversy concerning development of nuclear energy. Despite the safety record of the nation's nuclear power plants, these plants have become the target of certain groups claiming, through litigation or intervention in regulatory proceedings, that the present state of nuclear technology presents unacceptable risks to public health and safety and the environment. These claims may cause delays in, or interfere with, scheduled construction of new nuclear plants.

Although the Company is not aware of any existing or proposed environmental regulations having a significant effect upon its electric business,

Item 1. Business (Continued)

Environmental Matters (Continued)

it is unable to predict the possible effect on capital expenditures or earnings resulting from regulations which may be adopted in the future.

Employees

The Company has approximately 100 regular employees, of whom 68 were represented by the Utility Workers' Union of America, A.F.L.-C.I.O. The existing collective bargaining agreement expires May 31, 1983. Employee relations have generally been satisfactory.

Item 2. Properties

The Company operates a generating station located at the eastern end of the Cape Cod Canal in Sandwich, Massachusetts. The station consists of two oil-fired steam electric generating units: Canal Unit No. 1 with a rated capacity of 572 MW, which is wholly-owned by Canal; and Canal Unit No. 2, with a rated capacity of 584 MW, which is jointly-owned by Canal and Montaup Electric Company.

Item 3. Legal Proceedings

None

PART II.

Item 5. Market for the Registrant's Common Stock and Related Security Holder Matters

(a) Principal Market

Not applicable. The Company is a wholly-owned subsidiary of New England Gas and Electric Association.

(b) Approximate Number of Shareholders at December 31, 1980

One

(c) Frequency and Amount of Dividends Paid in 1980 and 1979

(Dollars in Thousands)

1980		1979	
Payment Date	Amount	Payment Date	Amount
April 29, 1980	$1 904	May 1, 1979	$1 447
July 29, 1980	1 447	July 31, 1979	1 523
October 27, 1980	1 523	October 19, 1979	1 523
December 26, 1980	1 523	December 27, 1979	1 143
	$6 397		$5 636

(d) Future dividends may vary depending upon the Company's earnings and capital requirements as well as financial and other conditions existing at that time.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

Item 7. Management's Discussion and Analysis of the Results of Operations

	Results of Operations For the Years Ended December 31, 1980	1979
	(Dollars in Thousands)	
Electric operating revenues	$197 256	$141 976
Costs and Expenses:		
Fuel oil used in production	161 722	110 832
Property taxes	1 791	1 623
Interest	4 299	4 178
Depreciation	4 617	4 596
Income taxes	6 459	5 653
All other, net	12 007	9 175
Total	190 895	136 057
Net income	$ 6 361	$ 5 919
Cash dividends declared on common stock paid to New England Gas and Electric Association (Parent Company)	$ 6 397	$ 5 636

Number of common shares outstanding 1 523 200

1980 Compared With 1979

Operating revenues increased by $55.3 million or approximately 38.9% over 1979. The power contracts for the sale of the capacity of the Canal units provide for the recovery of all operating expenses and fixed charges (including a return on equity) whether or not the unit is operating. Variations in revenue result from changes in operating expenses, primarily the cost of fuel oil and to a lesser degree from changes in the length of outages for scheduled maintenance. Such variations have no effect on net income. Fuel expense is the Company's single most significant operating cost, representing over 82% of the total revenue dollar. The average annual cost of fuel oil per barrel increased during 1980 to approximately $23.00, up from $16.00 in the prior year. Local property taxes increased by 10.4% due to a higher rate in effect and increased amounts of property. Income taxes increased as a result of higher pre-tax income. Other expenses of operations and maintenance increased by 27.8%. These higher costs reflect inflationary increases in material and labor costs and significantly higher maintenance costs for the Company's generating units. This added maintenance was due in part to the use of higher sulphur content fuel which, although it is lower priced and reduces fuel cost, causes added maintenance. In addition, a major dredging operation in the Cape Cod Canal contributed to this increase.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Canal Electric Company:

We have examined the balance sheets of CANAL ELECTRIC COMPANY (a Massachusetts corporation and wholly-owned subsidiary of New England Gas and Electric Association) as of December 31, 1980 and 1979, and the related statements of income, retained earnings and sources of funds used for construction for each of the three years in the period ended December 31, 1980, and the supporting schedule listed in the accompanying index. 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 Canal Electric Company as of December 31, 1980 and 1979, and the results of its operations and its sources of funds used for construction for each of the three years in the period ended December 31, 1980, and the supporting schedule present fairly the information required to be set forth therein, all in conformity with generally accepted accounting principles applied on a consistent basis.

ARTHUR ANDERSEN & CO.

Boston, Massachusetts,
February 17, 1981.

CANAL ELECTRIC COMPANY

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

PART II.

PART IV.

SCHEDULES OMITTED

All other schedules are not submitted because they are not applicable or required or because the required information is included in the financial statements or notes thereto.

CANAL ELECTRIC COMPANY

BALANCE SHEETS

DECEMBER 31, 1980 AND 1979

ASSETS

	1980	1979
	(Dollars in Thousands)	
PROPERTY, PLANT AND EQUIPMENT, at original cost:	$129 642	$128 854
Less - Accumulated depreciation	37 673	33 136
	91 969	95 718
Add - Construction work in progress	595	93
	92 564	95 811
CURRENT ASSETS:		
Cash	965	332
Temporary cash investments	25 900	5 400
Accounts receivable -		
Affiliated companies	13 437	9 217
Other	18 322	9 626
Prepaid taxes -		
Property	983	816
Income	-	139
Electric production fuel oil, at average cost	2 895	12 391
Other	357	237
	62 859	38 158
DEFERRED CHARGES (Note 7)	2 512	2 348
	$157 935	$136 317

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

CANAL ELECTRIC COMPANY

BALANCE SHEETS

DECEMBER 31, 1980 AND 1979

CAPITALIZATION AND LIABILITIES

	1980	1979
	(Dollars in Thousands)	
CAPITALIZATION:		
Common Equity -		
Common Stock, $25 par value -		
Authorized and outstanding -		
1,523,200 shares, wholly-owned by New England Gas and Electric Association (Parent)	$ 38 080	$ 38 080
Amounts paid in excess of par value	8 321	8 321
Retained earnings	7 214	7 250
	53 615	53 651
Long-term debt, including premiums, less current sinking fund requirements	49 130	49 893
	102 745	103 544
CURRENT LIABILITIES:		
Notes Payable to Banks (Schedule IX)	-	1 300
Other Current Liabilities -		
Current sinking fund requirements	890	686
Accounts payable -		
Affiliated companies	220	183
Other	29 657	9 450
Accrued taxes -		
Local property and other	983	817
Income	3 482	418
Deferred income	500	807
Accrued interest and other	1 352	1 346
	37 084	13 707
	37 084	15 007
DEFERRED CREDITS:		
Accumulated deferred income taxes	14 251	13 801
Unamortized investment tax credits	3 855	3 965
	18 106	17 766
COMMITMENTS (Note 7)		
	$157 935	$136 317

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

CANAL ELECTRIC COMPANY

STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978

	1980	1979	1978
	(Dollars in Thousands)		
ELECTRIC OPERATING REVENUES	$197 256	$141 976	$110 769
OPERATING EXPENSES:			
Fuel oil used in production	161 722	110 832	78 652
Other operation	6 882	6 301	6 269
Maintenance	7 705	4 107	4 225
Depreciation	4 617	4 596	4 568
Taxes -			
Income (Note 2)	6 459	5 653	6 455
Local property	1 791	1 623	1 552
Payroll and other	222	197	152
	189 398	133 309	101 873
OPERATING INCOME	7 858	8 667	8 896
OTHER INCOME:			
Allowance for equity funds used during construction	-	79	88
Other, net	2 802	1 351	1 217
	2 802	1 430	1 305
INCOME BEFORE INTEREST CHARGES	10 660	10 097	10 201
INTEREST CHARGES:			
Long-term debt	4 174	4 211	4 228
Other interest charges	161	43	-
Allowance for borrowed funds used during construction	(36)	(76)	(54)
	4 299	4 178	4 174
NET INCOME	$ 6 361	$ 5 919	$ 6 027

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

CANAL ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

FOR THE YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978

	1980	1979	1978
	(Dollars in Thousands)		
Balance at beginning of year	$ 7 250	$ 6 967	$ 6 805
Add (Deduct):			
Net income	6 361	5 919	6 027
Cash dividends on common stock	(6 397)	(5 636)	(5 865)
Balance at end of year	$ 7 214	$ 7 250	$ 6 967

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

STATEMENTS OF SOURCES OF FUNDS USED
FOR CONSTRUCTION

CANAL ELECTRIC COMPANY

STATEMENTS OF SOURCES OF FUNDS USED FOR CONSTRUCTION

FOR THE YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978

	1980	1979	1978
	(Dollars in Thousands)		
SOURCES OF FUNDS -			
Internal Sources			
From Operations -			
Net income	$ 6 361	$ 5 91[illegible]	$ 6 027
Items not requiring or (providing) funds:			
Depreciation	4 617	4 596	4 568
Deferred income taxes - long-term	451	1 997	1 352
Investment tax credits, net	(110)	(154)	(124)
Allowance for equity funds used during construction	-	(79)	(88)
	11 319	12 279	11 735
Less -			
Payment of dividends	6 397	5 636	5 865
Retirement of long-term debt through sinking funds	763	669	779
Other	114	36	(56)
	7 274	6 341	6 588
Changes in net current assets:			
Cash and temporary cash investments	(21 133)	8 334	3 484
Accounts receivable and unbilled revenue	(13 171)	(7 304)	2 595
Income taxes, net	2 896	693	(3 205)
Electric production fuel oil	9 496	(10 705)	(1 127)
Accounts payable and other	20 588	2 354	(5 802)
	(1 324)	(6 628)	(4 055)
Net available from internal sources	2 721	(690)	1 092
Increase (Decrease) in Interim Financing	(1 300)	1 300	-
	$ 1 421	$ 610	$ 1 092
FUNDS USED FOR CONSTRUCTION -			
Canal Unit No. 1	$ 1 241	$ 121	$ 521
Canal Unit No. 2	180	183	323
Jointly-Owned Project	-	385	336
	1 421	689	1 180
Less - Allowance for equity funds used during construction	-	79	88
	$ 1 421	$ 610	$ 1 092

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

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

(1) Accounting Policies

Transactions with Affiliates

The Company is a wholly-owned subsidiary of New England Gas and Electric Association. The Association is an exempt holding company under the provisions of the Public Utility Holding Company Act of 1935 and, in addition to its investment in the Company, has interests in other utility companies and several non-regulated companies.

Transactions between the Company and other system companies include purchase and sale of electricity and payment for management, accounting, data processing and other services. Transactions with other system companies are subject to review by the Federal Energy Regulatory Commission and the Massachusetts Department of Public Utilities.

Operating revenues include sales of electricity to affiliated companies of $105,279,000 in 1980, $75,870,000 in 1979 and $55,595,000 in 1978.

Other Major Customers

The Company is a wholesale electric generating company which sells power under life-of-the-unit power contracts to several utility companies in the New England area. Information regarding the customers and their participation in these contracts may be found in the "Business" section of this report.

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 Company's composite depreciation rate, based on average depreciable property in service, was 3.6% in 1980, 1979 and 1978.

Maintenance

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

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(1) Accounting Policies (Continued)

Allowance for Funds Used During Construction

The Company includes as an element of the cost of construction of depreciable propert an allowance for funds employed during periods when property is under construction. An amount equal to the allowance capitalized in the current period is reflected in the statements of income. Under applicable rate-making practices, property under construction is not included in rate base on which the Company is permitted to earn a return. Amounts so capitalized, while not currently providing funds, are included in rate base when property is placed in service, and these amounts are recoverable in revenues over the service life of the constructed property.

The Company develops rates based upon its current cost of capital and used a rate of 19% in 1980, 11 1/2% in 1979 and 11% in 1978.

(2) Income Taxes

For financial reporting purposes, the Company provides taxes on a separate return basis. However, for Federal income tax purposes, the Company's taxable income and deductions are included in the consolidated income tax return of its Parent and it makes tax payments or receives refunds on the basis of its tax attributes in the consolidated income tax return in accordance with applicable Federal income tax regulations.

The following is a summary of the provision for income taxes for the years ended December 31, 1980, 1979 and 1978:

	1980			1979			1978		
	Total	Federal	State	Total	Federal	State	Total	Federal	State
				(Dollars in Thousands)					
Currently payable	$6 436	$5 585	$851	$4 078	$3 537	$541	$5 183	$4 511	$672
Currently deferred	(318)	(275)	(43)	(268)	(270)	2	44	48	(4)
Long-term deferred	451	392	59	1 997	1 735	262	1 352	1 181	171
Investment tax credits	33	33	-	33	33	-	61	61	-
	6 602	5 735	867	5 840	5 035	805	6 640	5 801	839
Less-Amortization of investment tax credits	143	143	-	187	187	-	185	185	-
	$6 459	$5 592	$867	$5 653	$4 848	$805	$6 455	$5 616	$839

(2) Income Taxes (Continued)

Income taxes are provided for the tax effects of all timing differences other than certain construction-related costs. Timing differences result from reporting income and expense for tax purposes in periods different from those used for financial reporting purposes. The long-term deferred provision represents principally the tax effects arising from deducting depreciation for income tax purposes that currently exceeds the amounts provided in the accounts. The greater tax depreciation arises from the use of accelerated depreciation methods and shorter lives permitted by the Federal and state income tax laws. The tax effects of current timing differences are included in the current deferred provision and deferred income taxes. Investment tax credits are deferred and amortized over the life of the property giving rise to the credits.

The total income tax provision set forth above represents 50% in 1980, 49% in 1979 and 52% in 1978 of income before such income taxes. The table below reconciles the statutory Federal income tax rate to these percentages:

	1980	1979	1978
Statutory Federal income tax rate	46%	46%	48%
Increase (decrease) from statutory rate:			
State income tax net of Federal tax reduction	4	4	4
Other	-	(1)	-
	50%	49%	52%

The Company's long-term deferred provision for income taxes results from the use of the following:

	1980	1979	1978
	(Dollars in Thousands)		
Accelerated depreciation for tax purposes	$327	$1 242	$1 244
Allowance for borrowed funds used during construction	18	38	74
Other	106	717	33
Long-term deferred income tax provision	$451	$1 997	$1 351

(3) Interim Financing and Long-Term Debt

Notes Payable to Banks

The Company and other system companies have banking relationships in which borrowings are arranged as required for interim financing of construction in progress. These arrangements are not formal lines of credit but provide for unsecured borrowings evidenced by notes payable which are due within one year. The Company had no short-term borrowings outstanding and no existing lines of credit at December 31, 1980.

(3) Interim Financing and Long-Term Debt (Continued)

Long-Term Debt

Long-term debt outstanding, exclusive of current sinking fund requirements and related premiums, is as follows:

	Original Issue	Balance December 31, 1980	Balance December 31, 1979
	(Dollars in Thousands)		
First Mortgage Bonds,			
Series A, 7%, due 1996	$19 000	$14 440	$15 200
Series B, 8.85%, due 2006	35 000	34 650	34 650
		$49 090	$49 850

The Series A First Mortgage Bonds require an annual sinking fund payment of $760,000 from 1980 to 1996. At December 31, 1980 and 1979 the Company had purchased $220,000 and $424,000 of its bonds, respectively, in anticipation of future sinking fund requirements.

The Series B First Mortgage Bonds require an annual sinking fund payment of $350,000. The requirement may be met by payment, repurchase of bonds or certification of an amount of property additions equal to 60% of bondable property (as that term is defined in the indenture). The Company expects to certify additional bondable property in lieu of making sinking fund payments on these bonds.

(4) Dividend Restriction

At December 31, 1980, approximately $3,579,000 of retained earnings was restricted against payment of cash dividends by the terms of the Indenture of Trust securing long-term debt.

(5) Pension and Employee Savings Plans

The Company has a noncontributory pension plan covering substantially all regular employees who have attained the age of 25. 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 $325,000 in 1980, $298,000 in 1979 and $195,000 in 1978. The increases in expense are primarily due to changes in the plan which provide improved benefits to employees and retired personnel. A comparison of accumulated plan benefits and plan net assets for the Company's benefit plan is presented on the following page:

(5) Pension and Employee Savings Plans (Continued)

	January 1, 1980	January 1, 1979
	(Dollars in Thousands)	
Actuarial present value of accumulated plan benefits:		
Vested	$1 217	$ 990
Nonvested	156	124
Total actuarial present value of accumulated plan benefits	$1 373	$1 114
Net assets available for benefits	$1 282	$ 931

The plan uses a "5 year average of actual over expected return" method to determine the value of the accumulated plan benefits. Under this method an expected investment return is determined each year based on fund market value at the beginning of the year; contributions, benefit payments and expenses paid during the year; and the actuarial assumption as to rate of investment return, which is 6%. This expected return is compared to actual investment return and any excess is recognized over a five-year period.

The Company has an Employee Savings Plan which provides for Company contributions equal to contributions by eligible employees but not in excess of four percent of each employee's compensation rate. The total Company contribution was approximately $96,000 in 1980, $98,000 in 1979 and $78,000 in 1978.

(6) Property and Reserves

The major sub-classifications of property, plant and equipment at December 31, 1980, 1979 and 1978 were as follows:

	1980	1979	1978
	(Dollars in Thousands)		
Land and rights-of-way	$ 229	$ 229	$ 229
Structures and lease improvements	15 558	15 314	15 285
Production equipment	107 611	107 543	107 261
Transmission equipment	5 018	5 016	5 019
General equipment and vehicles	250	244	350
Total plant in service	128 666	128 346	128 144
Construction in progress	595	93	1 761
Nonutility property	840	372	234
Property held for future use	136	136	136
Total property, plant and equipment	$130 237	$128 947	$130 275

(6) Property and Reserves (Continued)

Neither the total additions to, nor reductions in property, plant and equipment during either of the years 1980, 1979 or 1978 amounted to more than 10% of the balance at the end of the respective years. The changes during the years are summarized as follows:

	1980	1979	1978
	(Dollars in Thousands)		
Balance at beginning of year	\$128 947	\$130 275	\$129 174
Additions, at original cost	1 421	689	1 180
	130 368	130 964	130 354
Retirements, at original cost -			
Charged to accumulated depreciation	131	34	79
Reclassification of joint-owned project	-	1 983	-
Balance at end of year	\$130 237	\$128 947	\$130 275

Changes in accumulated depreciation of property, plant and equipment during the years 1980, 1979 and 1978 are summarized as follows:

	1980	1979	1978
	(Dollars in Thousands)		
Balance at beginning of year	\$33 136	\$28 559	\$24 058
Provisions, charged to -			
Operating expense	4 617	4 596	4 568
Other	49	15	10
	37 802	33 170	28 636
Deductions -			
Retirements	131	34	79
Cost of removal, less salvage	(2)	-	(2)
	129	34	77
Balance at end of year	\$37 673	\$33 136	\$28 559

(7) Commitments

Construction Program

Construction expenditures for the five-year period ending in 1985 are estimated at \$157,300,000. Included in this amount is \$25,100,000 representing Commonwealth Electric's cost as of December 31, 1980 for the investment in jointly-owned generating facilities which the Company proposes to purchase, and approximately \$114,000,000 representing amounts presently committed by Commonwealth Electric applicable to such facilities for the five-year period. The Company will also assume additional commitments for construction costs, related to participation in the jointly-owned plants, for years beyond 1985. These amounts are estimated at \$8,800,000 and are based upon construction estimates of the lead participants.

(7) Commitments (Continued)

Construction Program (Continued)

The estimated construction costs and completion dates for these projects have changed as a result of regulatory, financing, legal and other problems associated with construction of nuclear and other generating facilities. The company is unable to predict what effect present or future construction difficulties related to these projects will have on its present construction estimates and the estimated completion dates.

Each of the participating utility companies finances its own share of the units. When these units become operational, the lead participant acts as the operator and bills the participants for their proportionate share of the expenses of the unit. Additional information relating to these units is contained in a table in Part I of this report under "Future Generating Plant Commitments."

Cancellation of Joint-Owned Project

The Company had a commitment to participate as a joint-owner in two nuclear generating units to be built by New England Power Company. In December, 1979 New England Power announced cancellation of its plans to build the power plants (NEP Units 1 and 2).

During 1980 the Company filed an application with the Federal Energy Regulatory Commission (FERC) seeking approval to write-off and recover its investment in the project which totaled approximately $1,764,000 and is included in deferred charges. In mid-December, 1980 FERC authorized the write-off of this investment over a three-year period beginning December 1, 1980. This investment is being recovered through capacity acquisition agreements with affiliated companies.

(8) 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 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.

Constant dollar amounts represent historical costs stated in terms of dollars of equal purchasing power, as measured by the Consumer Price Index for All Urban Consumers. Current cost amounts reflect the changes in specific prices of plant from the date the plant was acquired to the present, and differ from constant dollar amounts to the extent that specific prices have increased more or less rapidly than prices in general.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(8) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

The current cost of plant is determined primarily by indexing surviving plant using 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 productive capacity. Depreciation is determined by applying the Company's depreciation rates to the revised asset amounts.

Fuel inventories and the cost of fuel used in generation have not been restated from their historical cost in nominal dollars. Regulation provides for the recovery of fuel 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 ratemaking 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 constant dollars and 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. The Company does not have the opportunity to realize a gain on debt because it is limited to recovery only of the embedded cost of debt capital.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(8) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

FIVE YEAR COMPARISON OF SELECTED SUPPLEMENTARY FINANCIAL DATA ADJUSTED FOR EFFECTS OF CHANGING PRICES

(in thousands of average 1980 dollars)

	Year Ended December 31,				
	1980	1979	1978	1977	1976
Operating revenues:					
Actual	$197 256	$141 976	$110 769	$123 638	$108 285
Adjusted to average 1980 dollars	$197 256	$161 176	$139 907	$174 919	$156 743
Historical Cost Information adjusted for general inflation					
Income from continuing operations (excluding reduction to net recoverable cost)	$ 2 870	$ 2 438			
Net assets at year-end at net recoverable cost	$ 51 208	$ 57 556			
Current Cost Information					
Income from continuing operations (excluding reduction to net recoverable cost)	$ 1 875	$ 2 313			
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost	$ 6 712	$ 9 760			
Net assets at year-end at net recoverable cost	$ 51 208	$ 57 556			
General Information					
Gain from decline in purchasing power of net amounts owed	$ 4 640	$ 6 041			
Average consumer price index	246.8	217.4	195.4	181.5	170.5

Note: The Company's stock is entirely owned by the Parent, therefore, per share information is not relevant.

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS (CONTINUED)

(8) Supplementary Information to Disclose the Effects of Changing Prices (Unaudited) (Continued)

STATEMENT OF INCOME FROM CONTINUING OPERATIONS
ADJUSTED FOR CHANGING PRICES
For the Year Ended December 31, 1980

	Conventional Historical Cost	Constant Dollar Average 1980 Dollars	Current Cost Average 1980 Dollars
		(Dollars in Thousands)	
Operating revenues	$197 256	$197 256	$197 256
Fuel used in production	161 722	161 722	161 722
Depreciation expense	4 617	8 108	9 103
Other operating and maintenance expense	14 587	14 587	14 587
Income and other taxes	8 472	8 472	8 472
Interest expense	4 299	4 299	4 299
Other income and deductions - net	(2 802)	(2 802)	(2 802)
	190 895	194 386	195 381
Income (loss) from continuing operations (excluding reduction to net recoverable cost)	$ 6 361	$ 2 870*	$ 1 875
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 20 555
Reduction to net recoverable cost		$ (7 707)	(6 615)
Effect of increase in general price level			(20 652)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable cost			(6 712)
Gain from decline in purchasing power of net amounts owed		4 640	4 640
Net		$ (3 067)	$ (2 072)

* Including the reduction to net recoverable cost, the income (loss) from continuing operations on a constant dollar basis would have been ($4,837,000).

**At December 31, 1980, current cost of property, plant and equipment, net of accumulated depreciation was $182,387,000, while historical cost or net cost recoverable through depreciation was $92,564,000.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

PART IV.

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K

	Incorporated Documents Exhibit	SEC File No.	Filed Herewith at Page
(a) The following documents are filed as part of this report:			
1. Financial statements of the Company together with the Report of Independent Public Accountants, are filed under Item 8 of this report and listed on the Index to Financial Statements and Schedules in Item 8.			10
2. The following financial statement schedule is attached hereto:			
Schedule IX - Short-term borrowings for the year-ended December 31, 1980, 1979 and 1978.			33
(b) No reports on Form 8-K have been filed by the Company during the last quarter of the period covered by this report.			
(c) List of Exhibits:			
Exhibit 3. Articles of incorporation and by-laws.			
Filed herewith:			
3(a) Articles of incorporation of the Canal Electric Company. (Exhibit 1)			36
3(b) By-laws of the Company as amended to November 20, 1978. (Exhibit 2)			63
Exhibit 4. Instruments defining the rights of security holders, including indentures.			
Incorporated herein by reference thereto:			
4(b)1 Copy of Indenture of Trust and First Mortgage dated as of October 1, 1968 between the registrant and State Street Bank and Trust Company, Trustee, has been filed with the Commission as an exhibit to Form S-1.	4(b)	2-30057	

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents Exhibit	Incorporated Documents SEC File No.	Filed Herewith at Page
4(b)2	Copy of First and General Mortgage Indenture dated as of September 1, 1976, between the registrant and Citibank, N.A., Trustee, together with Cross Reference Sheet between Indenture and provisions of Trust Indenture Act of 1939, has been filed with the Commission as an exhibit to Form S-1.	4(b)2	2-56915	
4(b)3	Copy of First Supplemental Indenture dated as of September 1, 1976, to Indenture of Trust and First Mortgage dated as of October 1, 1968 between the registrant and State Street Bank and Trust Company, Trustee, closing such indenture, has been filed with the Commission as an exhibit to Form S-1.	4(b)3	2-56915	

Exhibit 10. Material contracts.

Incorporated herein by reference thereto:

		Exhibit	SEC File No.	Filed Herewith at Page
10(a)	Power contracts.			
10(a)(1)	Copies of power contracts dated December 1, 1965 between Canal Electric Company and other utility companies have been filed by Canal Electric Company with the Commission as an exhibit to Form S-1.	13(a)(1-4)	2-30057	
10(a)(2)	Copy of contract between Canal Electric Company and Montaup Electric Company and Stone & Webster Engineering Corporation, dated August 24, 1972, effective as of October 27, 1970, for the design and construction of Canal Plant Unit No. 2 at Sandwich, Massachusetts has been filed with the Commission as an exhibit to the 1972 Form 10-K.	1	2-30057	

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		
		Exhibit	SEC File No.	Filed Herewith at Page
10(a)(3)	The following have been filed with the Commission as exhibits to the 1975 Form 10-K of Canal Electric Company:			
	Copy of agreement between the registrant and Montaup Electric Company for use of common facilities by Canal Units I and II and for allocation of related costs, executed October 14, 1975.	1	2-30057	
	Copy of agreement between the registrant and Montaup Electric Company for joint ownership of Canal Unit II, executed October 14, 1975.	2	2-30057	
	Copy of agreement between the registrant and Montaup Electric Company for lease relating to Canal Unit II, executed October 14, 1975.	3	2-30057	
10(a)(4)	Copy of Contract dated January 12, 1976 between Canal Electric Company and New Bedford Gas and Edison Light Company and Cambridge Electric Light Company, affiliated companies, for the sale of specified amounts of electricity from Canal Unit No. 2 has been filed with the Commission as an exhibit to the 1975 New England Gas and Electric Association Form 10-K.	4	1-7316	
10(a)(5)	Copy of amendment dated August 6, 1976 to joint-ownership agreement between Canal Electric Company, New England Power Company, and other utilities dated January 11, 1976 has been filed with the Commission as an exhibit on Form 10-K of Canal Electric Company for the year ended December 31, 1976.	1	2-30057	

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		Filed Herewith at Page
		Exhibit	SEC File No.	
10(b)	Other agreements.			
10(b)(1)	The following contracts have been filed with the Commission as exhibits to Form S-7 of New England Gas and Electric Association:			
	Copy of Indenture of Lease between Canal Electric Company, Montaup Electric Company and Nepco Terminal, Inc. dated October 17, 1975 for the leasing of fuel oil tanks.	5(c)7	2-56476	
	Copy of Amendatory Agreement dated October 17, 1975 between Canal Electric Company and Nepco Terminal, Inc. amending fuel oil supply agreement dated June 2, 1967.	5(c)8	2-56476	
10(b)(2)	Copy of Employees Stock Ownership Plan and Trust of New England Gas and Electric Association and Subsidiaries has been filed with the Commission as an exhibit to Form S-7 of New England Gas and Electric Association.	5(c)8	2-55739	
10(b)(3)	Copy of letter agreement dated September 18, 1978 amending and extending the agreement dated June 6, 1967 between Canal Electric Company and Nepco Terminal, Inc. for the supply of fuel oil to Canal Electric Company has been filed with the Commission as an exhibit to the Association's 1978 Form 10-K.	4	1-7316	

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		Filed Herewith at Page
		Exhibit	SEC File No.	
10(b)(4)	Copy of First Amendment to Tax Reduction Act of 1975 Employees Stock Ownership Plan and Trust of New England Gas and Electric Association and Subsidiary Companies dated May 11, 1978 has been filed with the Commission as an exhibit to the Association's 1978 Form 10-K.	3	1-7316	
10(b)(5)	Copy of Employees Savings Plan of New England Gas and Electric Association and Subsidiary Companies as Amended January 1, 1979 has been filed as an exhibit to Form 8, Amendment to 1978 Form 10-K of New England Gas and Electric Association.	1	1-7316	
10(b)(6)	Copy of Pension Plan for Employees of New England Gas and Electric Association and Subsidiary Companies as Amended as of August 1, 1979 has been filed with the Commission as an exhibit to the Association's 1979 Form 10-K.	4	1-7316	
10(b)(7)	The following contracts have been filed with the Commission as exhibits to Form S-16 of New England Gas and Electric Association:			

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K (Continued)

		Incorporated Documents		Filed Herewith at Page
		Exhibit	SEC File No.	
10(b)(8)	Copies of New England Power Pool Agreement (NEPOOL) dated September 1, 1971 as amended through August 1, 1977, between NEGEA Service Corporation, as agent for Cambridge Electric Light Company, Canal Electric Company, New Bedford Gas and Edison Light Company, and various other electric utilities operating in New England, together with amendments dated August 15, 1978 and January 31, 1979.	5(c)13	2-64731	
	Copy of notice dated November 13, 1978 of non-extension of lease dated October 17, 1975 between Canal Electric Company and Montaup Electric Company for leasing of fuel oil tanks.	5(c)14	2-64731	
	Copy of amendment dated November 15, 1978 confirming and implementing letter agreement dated September 18, 1978 between Canal Electric Company and Nepco Terminal, Inc. for the supply of fuel oil.	5(c)15	2-64731	
	Copy of Facilities Lease and Operating Agreement dated November 15, 1978 between Canal Electric Company and Nepco Terminal, Inc. for the lease and operation of fuel oil terminal.	5(c)16	2-64731	

CANAL ELECTRIC COMPANY

Short-Term Borrowings

For the Years Ended December 31, 1980, 1979 and 1978

(Dollars in Thousands)

Category (A)	Notes Outstanding at Year-End	Weighted Average Interest Rate	Maximum Amount Outstanding During the Year	Average Amount Outstanding During the Year(B)	Weighted Average Interest Rate at Year-End(C)
	Year Ended December 31, 1980				
Banks	$ -	- %	$ -	$ -	- %
	Year Ended December 31, 1979				
Banks	$1 300	14.6%	$1 750	$254	16.5%
	Year Ended December 31, 1978				
Banks	$ -	- %	$ -	$ -	- %

(A) Refer to Note 3 of Notes to Financial Statements for the general terms of notes payable.

(B) The average amount of short-term debt outstanding is determined by averaging the level of short-term debt outstanding at month-end for the thirteen-month period ending December 31, 1980.

(C) The weighted average interest rate at year-end is determined by annualizing the interest cost based on rates in effect during December and dividing this by the notes outstanding at year-end.

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

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.

CANAL ELECTRIC COMPANY
(Registrant)

By: GERALD E. ANDERSON
Gerald E. Anderson,
Chairman of the Board and
President

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

Principal Executive Officer:

GERALD E. ANDERSON Gerald E. Anderson, Chairman of the Board and President	March 30, 1981

Principal Financial Officer:

EARL G. CHENEY Earl G. Cheney, Financial Vice President	March 27, 1981

Principal Accounting Officer:

JOHN A. WHALEN John A. Whalen, Comptroller	March 25, 1981

A majority of the Board of Directors:

________________ Charles T. Abbott, Director	March , 1981
GERALD E. ANDERSON Gerald E. Anderson, Director	March 30, 1981

CANAL ELECTRIC COMPANY

FORM 10-K DECEMBER 31, 1980

SIGNATURES
(Continued)

EARL G. CHENEY Earl G. Cheney, Director	March 27, 1981
LELAND R. CROWELL Leland R. Crowell, Director	March 23, 1981
JEREMIAH V. DONOVAN Jeremiah V. Donovan, Director	March 30, 1981
WILLIAM R. SMITH William R. Smith, Director	March 27, 1981
RICHARD G. VELTE Richard G. Velte, Director	March 27, 1981

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

For Quarter Ended March 31, 1981 Commission File Number 2-30057

CANAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Massachusetts (State or other jurisdiction of incorporation or organization)	04-1733577 (I.R.S. Employer Identification No.)
675 Massachusetts Avenue, Cambridge, Massachusetts (Address of principal executive offices)	02139 (Zip Code)

Registrant's telephone number, including area code 617 - 864 - 3100

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 and (2) has been subject to such filing requirements for the past 90 days. YES X NO ____

Shares of common stock outstanding at May 1, 1981 1,523,200

The Company meets the conditions set forth in General Instruction G(1)(a) and (b) of Form 10-Q as a wholly-owned subsidiary and is filing this Form with a reduced disclosure format.

PART I - FINANCIAL INFORMATION

Item 1. - Financial Statements

CANAL ELECTRIC COMPANY

CONDENSED BALANCE SHEETS

MARCH 31, 1981 AND DECEMBER 31, 1980

ASSETS

(Unaudited)

	March 31, 1981	December 31, 1980
	(Dollars in Thousands)	
PROPERTY, PLANT AND EQUIPMENT, at original cost:	$129 502	$129 642
Less - Accumulated depreciation	38 852	37 673
	90 650	91 969
Construction work in progress	922	595
	91 572	92 564
CURRENT ASSETS:		
Cash	598	965
Temporary cash investments	27 100	25 900
Accounts receivable -		
Affiliated companies	12 007	13 437
Other	12 922	18 322
Fuel inventory, at average cost	2 988	2 895
Prepaid property taxes and other	562	1 340
	56 177	62 859
DEFERRED CHARGES	2 691	2 512
	$150 440	$157 935

See accompanying notes.

CANAL ELECTRIC COMPANY

CONDENSED BALANCE SHEETS

MARCH 31, 1981 AND DECEMBER 31, 1980

CAPITALIZATION AND LIABILITIES

(Unaudited)

	March 31, 1981	December 31, 1980
	(Dollars in Thousands)	
CAPITALIZATION:		
Common Equity -		
Common stock, $25 par value - Authorized and outstanding - 1,523,200 shares, wholly-owned by Commonwealth Energy System (Parent)	$ 38 080	$ 38 080
Amounts paid in excess of par value	8 321	8 321
Retained earnings	8 883	7 214
	55 284	53 615
Long-term debt, including premiums, less current sinking fund requirements	48 940	49 130
	104 224	102 745
CURRENT LIABILITIES:		
Accounts payable	23 059	29 877
Accrued taxes	3 060	4 965
Other	1 769	2 242
	27 888	37 084
DEFERRED CREDITS:		
Accumulated deferred income taxes	14 480	14 251
Unamortized investment tax credits	3 848	3 855
	18 328	18 106
	$150 440	$157 935

See acccompanying notes.

CANAL ELECTRIC COMPANY

CONDENSED STATEMENTS OF INCOME AND UNAPPROPRIATED RETAINED EARNINGS

FOR THE THREE MONTHS ENDED MARCH 31, 1981 AND 1980

(Unaudited)

	1981	1980
	(Dollars in Thousands)	
ELECTRIC OPERATING REVENUES:		
Sales to affiliated companies	$38 411	$29 307
Sales to non-affiliated companies	28 356	24 637
	66 767	53 944
OPERATING EXPENSES:		
Fuel oil used in production	58 154	46 454
Other operation and maintenance	3 125	2 121
Depreciation	1 213	1 156
Taxes -		
Income	1 728	1 934
Local property	508	416
Payroll and other	83	71
	64 811	52 152
OPERATING INCOME	1 956	1 792
OTHER INCOME:		
Other, net	733	1 340
INCOME BEFORE INTEREST CHARGES	2 689	3 132
INTEREST CHARGES:		
Long-term debt	1 037	1 048
Other interest charges	6	141
Allowance for borrowed funds used during construction	(23)	-
	1 020	1 189
NET INCOME	1 669	1 943
UNAPPROPRIATED RETAINED EARNINGS - Beginning of Period	7 214	7 250
UNAPPROPRIATED RETAINED EARNINGS - End of Period	$ 8 883	$ 9 193

See accompanying notes.

CANAL ELECTRIC COMPANY

STATEMENTS OF SOURCES OF FUNDS USED FOR CONSTRUCTION

FOR THE THREE MONTHS ENDED MARCH 31, 1981 AND 1980

(Unaudited)

	1981	1980
	(Dollars in Thousands)	
SOURCES OF FUNDS -		
Internal Sources		
From operations -		
Net income	$ 1 669	$ 1 943
Items not requiring or (providing) funds:		
Depreciation	1 213	1 156
Deferred income taxes and investment tax credits, net	222	250
	3 104	3 349
Other Internal Sources (Uses) of Funds -		
Change in net current assets, exclusive of interim financing	(2 514)	(1 681)
Sinking fund payments	(190)	(190)
Other, net	(182)	(101)
	(2 886)	(1 972)
Net available from internal sources	218	1 377
Decrease in Interim Financing	-	(1 300)
FUNDS USED FOR CONSTRUCTION	$ 218	$ 77

See accompanying notes.

CANAL ELECTRIC COMPANY

NOTES TO CONDENSED FINANCIAL STATEMENTS

(1) Accounting Policies

The Company's significant accounting policies are described in Note 1 of Notes to Financial Statements included in its 1980 Annual Report on Form 10-K filed with the Securities and Exchange Commission. For interim reporting purposes, the Company follows these same basic accounting policies.

The financial statements reflect, in the opinion of the Company, all adjustments (which include only normal recurring adjustments) necessary to present fairly the results of operations for the periods ended March 31, 1981 and 1980.

The Company is a wholesale power company and operates its generating units under life-of-the-unit power contracts on file with the Federal Energy Regulatory Commission. These contracts provide for payment of demand charges which reimburse the Company on a monthly basis for a proportionate share of depreciation and capital costs as well as costs of operation and maintenance as these costs are incurred. Income tax expense is recorded using the statutory rates in effect applied to accounting income subject to tax recorded in the interim period. Accordingly, although revenues and operating expenses may fluctuate during interim periods, operating income before income taxes is relatively stable as to each unit.

(2) Commitments

The Company continues to assume commitments to participate as a joint-owner in generating units planned or under construction by other New England utilities. Reference is made to the Company's 1980 Annual Report on Form 10-K for information concerning these commitments.

On January 2, 1981 the Company entered into an agreement to acquire ownership in the Seabrook Nuclear Units 1 and 2 from Commonwealth Electric Company, an associated company. The Massachusetts Department of Public Utilities approved this transfer on April 15, 1981. Additional approvals are required from the Nuclear Regulatory Commission and the New Hampshire Public Service Commission before the actual transfer can be made.

(3) Name Change of the Parent Company

The name of the Parent organization has been changed from New England Gas and Electric Association to Commonwealth Energy System, effective May 11, 1981.

CANAL ELECTRIC COMPANY

Item 2. Management's Discussion and Analysis of the Results of Operations

The following is a discussion of certain significant factors which have affected operating revenues, expenses and net income during the periods included in the accompanying condensed statements of income. This discussion should be read in conjunction with the Notes to Condensed Financial Statements appearing elsewhere in this report.

The Company is a wholesale electric generating company operating two oil-fired turbine generators on a site in Sandwich, Massachusetts. Canal Unit No. 1 is wholly-owned by the Company, while Canal Unit No. 2 is jointly-owned by the Company and Montaup Electric Company.

The Company operates its generating units under power contracts which provide for the recovery of all operating expenses and fixed charges (including a return on equity) whether or not the units are operating. Variations in revenue result from changes in operating expense, primarily the cost of fuel oil and, in some periods, reflect the effects of outages for scheduled maintenance. Such variations have no significant effect on net income.

A summary of the period to period changes in the principal items included in the condensed statements of income for the three months ended March 31, 1981 and 1980 is shown below:

	Three Months Ended March 31, 1981 and March 31, 1980 Increases (Decreases) (Dollars in Thousands)	
Electric Operating Revenues	$ 12 823	23.8 %
Operating Expenses -		
Fuel used in production	11 700	25.2
Other operation and maintenance	1 004	[illegible]7.3
Depreciation	57	4.9
Taxes -		
Federal and state income	(206)	(10.7)
Local property and other	104	21.4
	12 659	24.3
Operating Income	164	9.2
Other Income	(607)	(45.3)
Income Before Interest Charges	(443)	(14.1)
Interest Charges	(169)	(14.2)
Net Income	$ (274)	(14.1)%
Energy Sales in Thousands KWH Increase (decrease)	(177 554)	(13.1)%

CANAL ELECTRIC COMPANY

Item 2. Management's Discussion and Analysis of the Results of Operations (Continued)

The following is a summary of Energy Sales for the three month period indicated:

	Unit 1	Unit 2	Total
KWH Sales in Thousands -			
Period Ended -			
March 31, 1981	678 122	504 444	1 182 566
March 31, 1980	851 117	509 003	1 360 120

Electric Revenues and Fuel Expense

Operating revenues for the first quarter of 1981 have increased by approximately \$12.8 million or 23.8% over the corresponding period of the prior year, despite a 13.1% decrease in unit sales. Unit sales have decreased during the current three-month period as the result of the timing of scheduled maintenance for Unit No. 1. The increase in revenues reflects an increase in the cost of fuel oil, which averaged 4.92¢ per KWH in the current period as compared to 3.42¢ per KWH in the comparable period of the prior year. The price of fuel oil at Canal Electric is currently approaching \$33 per barrel as compared with \$24 per barrel one year ago.

Operating Expenses

Operating expenses, other than fuel costs and income taxes, for the current three months have increased by approximately 32.4% primarily due to the impact of inflation on wage rates and material costs and a 22.1% increase in local property taxes in the Town of Sandwich.

The 10.7% decrease in Federal and state income taxes is attributable to a 12.4% decrease in taxable income.

Other Income and Interest Charges

The 45.3% decrease in other income during the current three month period is due to a significant reduction in income from non-utility operations. This was offset, somewhat, by an increase in interest income. Short-term interest charges decreased because of the elimination of short-term borrowings.

CANAL ELECTRIC COMPANY

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

None

Item 5. Other Information

None

Item 6. Exhibits and Reports on Form 8-K

(a) List of Exhibits:

	Incorporated Document Exhibit	Incorporated Document SEC File No.	Filed Herewith at Page
Exhibit 10. Material Contracts.			
Incorporated herein by reference to the following:			
10(a)(6) Copy of agreement dated January 2, 1981 to transfer ownership, construction and operational interest in the Seabrook Units 1 and 2 from Commonwealth Electric Company (formerly New Bedford Gas and Edison Light Company) to Canal Electric Company has been filed with the Commission on Commonwealth Electric Company's Form 10-Q (March 1981).	1	2-7749	
Exhibit 20. Previously unfiled documents.			
Filed herewith as Exhibit No. 1:			
20(a) Copy of the Capacity Acquisition Agreement dated September 25, 1980 between Canal Electric Company, Cambridge Electric Light Company and Commonwealth Electric Company.			11

(b) Reports on Form 8-K. There were no reports filed on Form 8-K for the three months ended March 31, 1981.

CANAL ELECTRIC COMPANY

PART II - OTHER INFORMATION (CONTINUED)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CANAL ELECTRIC COMPANY
(Registrant)

Principal Financial Officer:

EARL G. CHENEY
Earl G. Cheney
Financial Vice President

Principal Accounting Officer:

JOHN A. WHALEN
John A. Whalen
Comptroller

Date: May 12, 1981

P R O S P E C T U S

$35,000,000

Canal Electric Company

(A subsidiary of New England Gas and Electric Association)

First and General Mortgage Bonds, Series B 8.85% Due 2006

Interest payable March 1 and September 1 *Due September 1, 2006*

The Series B Bonds will be redeemable at the redemption prices set forth herein, provided that prior to September 1, 1986 no redemption may be made at a general redemption price through refunding at a net interest cost to the Company less than the interest rate of the Series B Bonds.

THESE SECURITIES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION NOR HAS THE COMMISSION PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

	Price to Public(1)	Underwriting Commissions(2)	Proceeds to Company(3)
Per Unit	101.055%	1.000%	100.055%
Total	$35,369,250	$350,000	$35,019,250

(1) Plus accrued interest from date of original issue.

(2) The Company has agreed to indemnify the several Underwriters against certain civil liabilities, including liabilities under the Securities Act of 1933.

(3) Before deduction of expenses payable by the Company estimated at $195,000.

The Series B Bonds are offered by the several Underwriters when, as and if issued by the Company and accepted by the Underwriters and subject to their right to reject orders in whole or in part. It is expected that the Series B Bonds, in definitive fully registered form, will be ready for delivery on or about September 16, 1976.

The First Boston Corporation

The date of this Prospectus is September 9, 1976.

IN CONNECTION WITH THIS OFFERING, THE UNDERWRITERS MAY OVER-ALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF THE SECURITIES HEREBY OFFERED AT A LEVEL ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

THE COMPANY

Canal Electric Company (the "Company"), a wholly-owned subsidiary of New England Gas and Electric Association (the "Association"), is a wholesale electric generating company organized under the laws of the Commonwealth of Massachusetts. The Company's executive offices are located at 675 Massachusetts Avenue, Cambridge, Massachusetts 02139 and its telephone number is (617) 864-3100.

The Company's generating facilities are located in Sandwich, Massachusetts at the eastern end of the Cape Cod Canal. Construction of the first generating unit at the Canal site ("Unit No. 1") was completed in 1968. A second unit ("Unit No. 2"), in which the Company has a one-half ownership interest, commenced commercial operation February 1, 1976. During 1975 the Company made a commitment to participate as a joint owner of a nuclear generating plant to be constructed by another New England utility. The Company expects to participate as a joint owner of other generating units to be located in New England.

APPLICATION OF PROCEEDS

The Company will use the proceeds of approximately $35,000,000 from the sale of the Series B Bonds to repay outstanding short-term loans. In June and August 1976, the Company received $27,000,000 from the sale of additional common stock to the Association, which proceeds were also used to repay short-term loans. The $62,000,000 of short-term loans were incurred to finance additions to property, plant and equipment, principally the Company's one-half share of construction costs relating to Unit No. 2.

CERTAIN FACTORS AFFECTING THE INDUSTRY

The electric utility industry, in general, is currently experiencing problems including high fuel prices, obtaining sufficient capital on reasonable terms, compliance with nuclear and environmental regulations and construction delays.

These problems are being experienced in varying degrees by different companies and areas. For a further discussion of these problems as they have affected the Company, see "Construction and Financing", "Management's Discussion and Analysis of the Statements of Income" and "Business — Future Generating Plant Commitments, — Fuel Supply, and — Environmental Matters". The Company is unable to predict their future impact on its operations.

THE ISSUE IN BRIEF

The following material is qualified in its entirety by the detailed information and financial statements (including the notes thereto) appearing elsewhere in this Prospectus.

THE OFFERING

Issuer	Canal Electric Company
Security Offered	$35,000,000 First and General Mortgage Bonds, Series B 8.85% Due 2006
Expected Offering Date	September 9, 1976
Interest Payment Dates	March 1 and September 1
Maturity Date	September 1, 2006
Use of Proceeds	To repay short-term loans incurred to finance additions to property, plant and equipment, principally the Company's one-half ownership interest in Unit No. 2

THE COMPANY

Principal Business	The generation and sale of electricity at wholesale under long-term contracts
Sales for the twelve months ended June 30, 1976	4,363,000 MWH
Generating Capacity	862 MW

FINANCIAL INFORMATION

	Year Ended December 31, 1975	Twelve Months Ended June 30, 1976
Operating revenues	$82,322,000	$93,236,000
Net income	$ 3,829,000	$ 3,971,000
Ratio of earnings to fixed charges — Actual	1.87	2.04
Pro Forma	—	3.01

	(Dollars in Thousands)			
	Outstanding	Ratios	As Adjusted*	Ratios
Capitalization, June 30, 1976:				
Long-term debt	$18,188	36.0%	$ 53,188	50.0%
Common equity	32,296	64.0	53,244	50.0
Total	$50,484	100.0%	$106,432	100.0%
Interim Financing:				
Notes payable to banks	$62,300		$ —	
Notes payable to the Association	2,350		700	
Total	$64,650		$ 700	

*See "Capitalization" herein.

CONSTRUCTION AND FINANCING

The Company's 1976 construction expenditures are estimated at $12,600,000, of which $2,800,000, principally relating to construction of Unit No. 2, has been expended through June 30, 1976. Expenditures for the balance of 1976 relate primarily to acquisition of ownership interests in certain jointly-owned generating facilities now under construction by other electric utility companies in New England. The Company proposes to purchase such interests from New Bedford Gas and Edison Light Company, another subsidiary of the Association, at New Bedford's cost of $9,700,000. See "Business — Future Generating Plant Commitments".

Construction expenditures for the period from January 1, 1977 through December 31, 1980 are estimated at $80,100,000. These expenditures are principally for the Company's proportionate share of construction costs of jointly owned electric generating plants and include amounts presently committed by New Bedford for its joint ownership interests. The Company has or will assume commitments amounting to an additional $176,000,000 relating to its participation in these jointly-owned plants during the period 1981 through 1988, when construction of the last of these units is scheduled for completion.

The Company's construction program is subject to periodic review, and actual expenditures may vary from the above estimates because of factors such as changes in business conditions, rates of growth, effects of inflation, equipment delivery schedules, licensing delays, availability and cost of capital, and environmental factors. Estimated construction expenditures relating to the jointly-owned generating units are based upon the most recent information furnished by the utility responsible for the construction of each unit.

During the five year period ending December 31, 1980, it is estimated that internal resources will provide approximately $20,000,000 to be used for construction. The balance of the funds required will be provided by short-term borrowings, which are expected to be replaced by long-term debt and equity securities.

Financings presently planned for the period ending December 31, 1980 consist of long-term debt issues aggregating $76,000,000 and $49,000,000 from the sale of equity securities to the Association. These amounts include the proceeds of the Series B Bonds offered hereby and $27,000,000 from the sale of common stock to the Association in June and August 1976. The exact type, timing and amount of future long-term debt and equity financings are subject to change because of market conditions and other factors.

CAPITALIZATION

The capitalization of the Company as of June 30, 1976, and as adjusted to reflect the issuance and sale of the Series B Bonds, the sale of common stock to the Association and the application of the proceeds therefrom, is set forth below:

	June 30, 1976		
	Outstanding(a)	Adjusted	
		Amount	Ratios
	(Dollars in Thousands)		
Long-term Debt (including premiums and current sinking fund requirements)(b):			
First Mortgage Bonds, Series A, 7%, Due 1996	$18,188	$ 18,188	
First and General Mortgage Bonds, Series B 8.85% Due 2006	—	35,000	
Total Long-term Debt	18,188	53,188	50.0%
Common Equity:			
Common stock, $25 par value	23,048	38,080	
Amounts paid in excess of par value	2,404	8,320	
Retained earnings(c)	6,844	6,844	
Total Common Equity	32,296	53,244	50.0
Total Capitalization	$50,484	$106,432	100.0%
Interim Financing, due within one year(d)(e):			
Notes payable to banks	$62,300	$ —	
Notes payable to the Association	2,350	700	
Total Interim Financing	$64,650	$ 700	
Number of Shares of Common Stock Outstanding	921,900	1,523,200	

(a) Amounts outstanding reflect the issuance on June 30, 1976 of 173,700 shares of common stock to the Association and application of $6,050,000 of the proceeds therefrom to reduction of notes payable to banks.

(b) The aggregate authorized amount of bonds which may be issued under the Company's First and General Mortgage Indenture is unlimited, and additional bonds may be issued thereunder subject to the restrictions set forth therein. No additional bonds will be issued under the indenture securing the Series A Bonds (see "Description of Series B Bonds — General").

(c) Reference is made to "Description of Series B Bonds — Dividend Restriction" and to Note 3 of Notes to Financial Statements for information concerning limitation on payment of cash dividends.

(d) The weighted average interest rate at June 30, 1976 was 7.6% on notes payable to banks and 7¼% for the notes payable to the Association.

(e) After the application of the remaining $55,950,000 proceeds from 1976 financings ($35,000,000 from the sale of the Series B Bonds and $20,950,000 from the sale in August 1976 of 601,300 additional shares of common stock to the Association), the Company will have available to further reduce short-term loans an additional $8,000,000 maintained as compensating bank balances.

(f) Reference is made to Note 5 of Notes to Financial Statements for information concerning obligations under long-term leases.

CANAL ELECTRIC COMPANY

STATEMENTS OF INCOME

The following Statements of Income of Canal Electric Company for the five years ended December 31, 1975 have been examined by Arthur Andersen & Co., independent public accountants, as set forth in their report included elsewhere in this Prospectus. The Statement of Income for the twelve months ended June 30, 1976, not examined by independent public accountants, reflects, in the opinion of the Company, all adjustments (which include only normal recurring adjustments) necessary to present fairly the results of operations for such period. These Statements should be read in conjunction with the financial statements and related notes included elsewhere in this Prospectus.

	Year Ended December 31,					Twelve Months Ended June 30,
	1971	1972	1973	1974	1975	1976
	(Dollars in Thousands)					(Unaudited)
ELECTRIC OPERATING REVENUES:						
Sales to non-affiliated companies	$20,956	$22,572	$30,076	$60,818	$61,729	$64,964
Sales to affiliated companies	7,008	7,521	10,019	20,244	20,593	28,272
	27,964	30,093	40,095	81,062	82,322	93,236
OPERATING EXPENSES:						
Fuel oil used in production	16,002	17,815	27,414	65,782	67,575	72,725
Other operation	2,236	2,453	2,539	2,813	3,178	4,602
Maintenance (Note 1)	1,002	697	910	2,543	1,750	1,690
Depreciation (Note 1)	2,064	2,161	2,282	2,325	2,367	3,234
Taxes —						
Income (Note B)	2,096	2,008	1,428	212	58	1,817
Local property	732	1,025	927	1,040	1,181	1,264
Payroll and other	40	41	54	69	81	100
	24,172	26,200	35,554	74,784	76,190	85,432
OPERATING INCOME	3,792	3,893	4,541	6,278	6,132	7,804
OTHER INCOME:						
Allowance for funds used during construction (Notes A and 1)	151	299	921	2,702	4,125	2,570
Other, net	—	13	144	51	125	192
	151	312	1,065	2,753	4,250	2,762
TOTAL INCOME	3,943	4,205	5,606	9,031	10,382	10,566
INTEREST EXPENSE:						
Long-term debt	1,628	1,548	1,563	1,531	1,399	1,338
Short-term debt	211	506	1,704	4,644	5,154	5,257
	1,839	2,054	3,267	6,175	6,553	6,595
NET INCOME	$ 2,104	$ 2,151	$ 2,339	$ 2,856	$ 3,829	$ 3,971
Ratio of Earnings to Fixed Charges (Note C)	3.06	2.89	2.20	1.72	1.87	2.04

Numbered notes refer to Notes to Financial Statements. All such notes and the notes on the following pages are an integral part of these Statements of Income.

CANAL ELECTRIC COMPANY

NOTES TO STATEMENTS OF INCOME

(Including Information Applicable to Unaudited Period)

(A) Allowance for Funds Used During Construction ("AFUDC")

The Company reflects as an element of the cost of construction of depreciable property an allowance for funds (including common equity funds) employed during periods when property is under construction. An amount equal to AFUDC capitalized in the current period, while not currently providing funds, is reflected as Other Income. Under applicable rate making principles, property under construction is not included in rate base on which the Company is permitted to earn a return. Amounts so capitalized are included in rate base when property is placed in service, and are thereafter recoverable in revenues over the service life of the constructed property.

The amount of AFUDC recorded is determined by multiplying the average monthly dollar balance of construction work in progress by a rate related to the current after-tax cost of capital. The Company used a rate of 7% through June 30, 1973, 9% through June 30, 1974, 9½% through March 31, 1975 and 8½% thereafter.

Assuming that funds used to finance construction were supplied in the same proportion as the Company's average capitalization ratios for each period (ranging from 53% to 76% for debt and 47% to 24% for common equity) and that the cost of borrowings used to finance construction was equivalent to the after-tax cost of short-term debt, the portion of net income represented by the equity component of AFUDC was 5% in 1971, 10% in 1972, 26% in 1973, 46% in 1974, 61% in 1975 and 36% for the twelve months ended June 30, 1976.

(B) Income Taxes

For financial reporting purposes, the Company calculates income tax expense as if it filed a separate income tax return. However, for Federal income tax purposes, the Company's taxable income and deductions are included in the consolidated income tax return of the Association, and it makes tax payments or receives refunds on the basis of its tax attributes in the consolidated income tax return in accordance with applicable Federal income tax regulations. The following is a summary of the provision for income taxes for the five years ended December 31, 1975 and the twelve months ended June 30, 1976:

(B) Income Taxes — (Continued)

	Year Ended December 31,					Twelve Months Ended June 30,
	1971	1972	1973	1974	1975	1976
	(Dollars in Thousands)					(Unaudited)
Provision Charged to Operating Expense:						
Current —						
Federal	$1,324	$ 990	$ (217)	$ (637)	$ (572)	$ (521)
State	192	146	99	—	15	132
	1,516	1,136	(118)	(637)	(557)	(389)
Deferred —						
Federal	554	798	1,368	835	416	885
State	81	115	96	36	192	232
	635	913	1,464	871	608	1,117
Investment tax credits deferred, net	(55)	(41)	82	(22)	7	1,089
Total	2,096	2,008	1,428	212	58	1,817
Deferred income taxes classified as a reduction of AFUDC:						
Federal	32	66	290	1,294	1,763	1,091
State	5	9	42	187	172	107
	37	75	332	1,481	1,935	1,198
Total Income Tax Provision	$2,133	$2,083	$1,760	$1,693	$1,993	$3,015

Income taxes are provided for the tax effects of timing differences other than certain construction related costs. Timing differences result from reporting income and expense for tax purposes in periods different from those used for financial reporting purposes. The current provision for income taxes includes amounts which are not currently payable but which are recorded as a current liability because they relate to assets which are classified as current. The deferred provision represents principally the tax effects arising from deducting depreciation for income tax purposes that currently exceeds the amount provided in the accounts. The greater tax depreciation arises from the use of accelerated depreciation methods and shorter lives permitted by the Federal income tax laws. Investment tax credits are deferred and amortized over the life of the property giving rise to the credits. The amount of AFUDC capitalized is based upon the Company's after-tax cost of capital and accordingly is net of related income taxes.

For Federal income tax purposes, consolidated net operating losses resulting from timing differences and investment tax credits which have not been used for tax purposes may be carried forward and applied to reduce future taxes payable. The Company's allocable portion of these future tax benefits approximated $965,000 at December 31, 1975. For accounting purposes, these amounts have been recorded as a reduction of the Federal income tax provision related to current timing differences.

(B) Income Taxes — (Continued)

There is no provision permitting carryforward of net operating losses for state tax purposes and the Company has provided additional state income taxes to the extent that net operating losses result from timing differences.

The total Federal income tax provision set forth above represents from 30% to 48% of income before such taxes during the periods presented. The table below reconciles these percentages to the statutory Federal income tax rate.

	Year Ended December 31,					Twelve Months Ended June 30,
	1971	1972	1973	1974	1975	1976 (Unaudited)
Total Federal income tax provision	48%	47%	41%	35%	30%	40%
Reduction in Federal income tax expense due to exclusion of the equity portion of AFUDC	1	3	7	15	20	10
Amortization of investment tax credits	1	1	1	1	1	2
Other — related to timing differences for which taxes are not provided	(2)	(3)	(1)	(3)	(3)	(4)
Statutory Federal income tax rate	48%	48%	48%	48%	48%	48%

(C) Ratio of Earnings to Fixed Charges

For purposes of computing the ratio, earnings have been calculated by adding to net income, taxes based on income and fixed charges. Fixed charges consist of interest expense (including amortization of debt expense and premium on debt) and the portion of rentals estimated to be representative of interest.

The unaudited pro forma ratio of earnings to fixed charges for the twelve months ended June 30, 1976 is 3.01. The calculation of this ratio gives effect to the annual interest charges on the Series B Bonds ($3,097,500); and adjustments to interest expense to reflect (i) the repayment of short-term indebtedness totalling $62,000,000 from the proceeds of the Series B Bonds and the sale of common stock to the Association; (ii) the repayment of additional short-term indebtedness totalling $8,000,000 by application of compensating bank balances; and (iii) increased short-term borrowings totalling $13,800,000 presently proposed for the period ending June 30, 1977.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF THE STATEMENTS OF INCOME

Throughout the periods covered, the statements of income reflect the results of commercial operation of Unit No. 1. Through January 31, 1976, the statements of income also reflect the effects of construction of Unit No. 2. The statement of income for the twelve months ended June 30, 1976 reflects the results of operation of Unit No. 2 commencing February 1, 1976. Significant changes in items of income and expense are explained in further detail below.

Operating Revenues

In each of the five years ended December 31, 1975 and the twelve months ended June 30, 1976, operating revenues have increased over the prior period by the following percentages: 45.3%, 7.6%, 33.2%, 102.2%, 1.6% and 10.4%. Unit No. 1 has operated near its design capability during the periods covered by the statements of income except for periods of scheduled maintenance. The power contracts for the sale of the capacity of Unit No. 1 provide fo. .e recovery of all operating expenses and fixed charges (including a return on equity) whether or not the unit is operating (see "Business — Power Contracts"). Variations in revenue result from changes in operating expenses, primarily the cost of fuel oil (see "Operating and Interest Expenses" below), and to a lesser degree f.om changes in the length of outages for scheduled maintenance. Such variations have no effect on net income.

Except for the twelve months ended June 30, 1976, there are no operating revenues applicable to Unit No. 2 included in the statements of income.

Operating and Interest Expenses

The magnitude of changes in major elements of expense is shown below:

	Percentage Increase (Decrease) Over Prior Period					
	1971	1972	1973	1974	1975	1976
Fuel oil used in production	110.7	11.3	52.4	140.0	2.7	6.0
Property taxes	11.8	40.0	(9.6)	12.2	13.6	9.5
Other operation	8.8	9.7	3.5	10.8	13.0	46.5
Maintenance	31.8	(30.4)	30.6	179.5	(31.2)	(47.0)
Interest	(2.2)	11.7	59.1	89.0	6.1	(2.8)
Depreciation	1.1	4.7	5.6	1.9	1.8	36.6

Increases in operating expenses result from the higher cost of imported fuel oil and the higher cost of low sulphur fuel oil required to meet pollution control requirements and from general inflation affecting wage rates and material costs.

Fuel expense is the Company's single most significant operating cost and in recent periods represented more than 80% of each revenue dollar. The Company's average annual cost per barrel of fuel oil increased from \$3.13 in 1971 to \$13.20 in 1974. This cost declined slightly during 1975 and in the twelve-month period ended June 30, 1976, averaged approximately \$11.15 per barrel. Fuel cost per KWH was .5¢ in 1971 and 1972, .7¢ in 1973, 1.9¢ in 1974, 1.8¢ in 1975 and 1.7¢ for the twelve months ended June 30, 1976.

Property taxes and depreciation have increased mainly as a result of additions to operating property and equipment over the period. The decrease in property taxes in 1973 is attributable to a decrease in the property tax rate in the town of Sandwich. The increase in maintenance expense in 1974

reflects major scheduled maintenance performed during that year. Variations in maintenance expense in other periods reflect the timing of scheduled maintenance of Unit No. 1.

Interest expense increased sharply during the period 1972 through 1974 as a result of increased short-term borrowings necessary to finance construction of Unit No. 2 and the general increase in interest rates in 1973 and 1974.

Other Income

The increase in AFUDC for the period 1973 through 1975 is due to the increase in construction work in progress applicable to Unit No. 2. The amount of AFUDC capitalized by the Company with respect to Unit No. 2 is based upon the current after-tax cost of capital. Income taxes charged to operating expenses exclude deferred income taxes classified as a reduction of AFUDC. See Note B of Notes to Statements of Income.

Twelve Months Ended June 30, 1976

Unit No. 2 commenced commercial operation February 1, 1976. Operation of the new unit contributed to increased revenues and operating expenses during the twelve months ended June 30, 1976 as explained above and also caused the decrease in AFUDC. The net effect of these changes contributed to an increase in net income.

Quarterly Information

The following quarterly information pertains to the results of operations for the six month periods ended June 30, 1976 and June 30, 1975. Increases in operating revenues, operating income, total income and net income in the first six months of 1976 as compared to the corresponding period in 1975 are due to commercial operation of Unit No. 2.

	1976 by Quarter		1975 by Quarter	
	1st	2nd	1st	2nd
	(Dollars in Thousands)			
Operating Revenues	$26,955	$23,350	$23,382	$16,009
Operating Income	2,230	2,525	1,668	1,416
Total Income	2,630	2,591	2,601	2,436
Net Income	1,016	922	865	931

BUSINESS

General

The Company was organized in 1902 as an electric distribution company and assumed its present corporate name in 1966 after the sale to an affiliated company of its electric distribution and transmission properties together with the right to do business in the territories served. The only assets retained after this sale consisted of cash, land and Unit No. 1, then in its initial stage of construction, together with the right to generate, transmit and sell electricity at wholesale.

Unit No. 1 and Unit No. 2 are located on a site containing approximately 90 acres of land owned by the Company in Sandwich, Massachusetts. The principal components of Unit No. 1 and Unit No. 2 are 572 MW and 580 MW (net output) turbine generators, respectively. Each unit consists of multiple turbines driving a single generator, and an oil-fired steam supply unit. Water used for condensing purposes for both units is withdrawn from the Cape Cod Canal via separate intake structures and

returned to the canal via a common discharge flume. Both units share a 500 foot stack. Unit No. 1 is designed as a base load unit, and Unit No. 2 is designed for cyclic operation permitting efficient reduced generation during nights and weekends.

Unit No. 1 is wholly owned by the Company. Unit No. 2 is jointly owned by the Company and Montaup Electric Company (a non-affiliated company) and is operated by the Company under an agreement providing for equal sharing of output, costs and operating expenses.

Power Contracts

The Company has entered into substantially identical life of the unit power contracts with Boston Edison Company, Montaup Electric Company and New England Power Company, under each of which the customer is severally obligated to purchase one quarter of the power output of Unit No. 1, and with New Bedford Gas and Edison Light Company ("New Bedford") and Cambridge Electric Light Company ("Cambridge Electric"), both distribution subsidiaries of the Association, under which the two are jointly obligated to purchase the remaining one quarter of the unit's output.

A similar contract is in effect between the Company and New Bedford and Cambridge Electric, under which those companies are jointly obligated to purchase the Company's entire one-half share of the net capability of Unit No. 2. As permitted by such contract, however, the Company has contracted to sell a portion of such capability to two other non-affiliated companies until October 31, 1978.

The price of power under the power contracts is based on a two-part rate consisting of a demand rate and an energy rate. The demand rate covers all expenses except fuel costs and provides for a return on investment as well as recovery of investment over the depreciable lives of the units. The energy rate is based on the cost of fuel and is billed to each purchaser in proportion to its consumption of power. Purchasers are billed on a monthly basis. The power contracts are on file with the Federal Power Commission ("FPC") (see "Business — Regulation").

The obligation of the purchasers to make payments under the power contracts is unconditional, subject only to each purchaser's right to cancel its power contract if deliveries cannot be made because either (i) the unit is damaged to the extent of being completely or substantially completely destroyed, (ii) the unit is taken by exercise of the right of eminent domain or a similar right or power, or (iii)(a) the unit cannot be used because a necessary license or other necessary public authorization cannot be obtained or is revoked, or because the use of such license or such authorization is made subject to specified conditions which are not met, and (b) the situation cannot be rectified to an extent which will permit the Company to make deliveries to the purchaser from the unit.

The power contracts require that the Company maintain insurance on both units against all property risks on which insurance is available. No assignment of a power contract (except to a corporate successor) will relieve a purch... of its obligations without the consent of the Company and the remaining purchasers.

The Company has no liability under the power contracts to any purchaser because of non-delivery of power for reasons beyond the Company's reasonable control and the purchasers do not have the right to set off against payments required to be made under the power contracts other amounts owed to them by the Company.

The Company expects to enter into similar life of the unit contracts with distribution subsidiaries of the Association for the purchase from the Company of its entitlement in the power output of future generating plants in which the Company participates as a joint owner (see "Business — Future Generating Plant Commitments").

Principal Customers

The following is a description of the purchasers with which the Company has long-term power contracts:

Boston Edison Company is the third largest electric utility in New England, based on electric sales for 1975. It supplies electricity at retail to approximately 592,000 customers in the city of Boston and a surrounding area within 30 miles of Boston. This service area is approximately 590 square miles with a population of over 1,600,000.

Montaup Electric Company is the electric generating company of the Eastern Utilities Associates system. Substantially all of its generation is sold to Blackstone Valley Electric Company, Brockton Edison Company and Fall River Electric Light Company, distribution subsidiaries of Eastern Utilities Associates. This system supplies electricity to approximately 218,000 customers in the Woonsocket-Pawtucket area of Rhode Island and the Fall River and Brockton areas of Massachusetts, which have a combined population of 642,000.

New England Power Company is engaged in generating, purchasing and transmitting electricity at wholesale principally to other electric utilities. The company is a subsidiary of New England Electric System, the second largest electric utility system in New England. The distribution subsidiaries of New England Electric System supply electricity at retail to approximately 990,000 customers in an area exceeding 4,500 square miles having a population of 2,700,000. The principal areas served by the system are in the states of Massachusetts and Rhode Island with some sales in New Hampshire and Vermont.

Cambridge Electric Light Company is engaged in the generation, distribution and sale of electricity to approximately 40,000 customers in the city of Cambridge, Massachusetts, an area of approximately seven square miles with a population of approximately 100,000. In addition, it sells wholesale power to the town of Belmont.

New Bedford Gas and Edison Light Company distributes and sells electricity to approximately 200,000 customers (including approximately 31,000 seasonal customers) in 40 communities in southeastern Massachusetts including Cape Cod and the island of Martha's Vineyard, having an approximate year-round population of 356,000. New Bedford also distributes and sells natural gas to approximately 46,000 customers in eleven of the same communities.

New England Power Pool

The Company is a member of the New England Power Pool ("NEPOOL"), which was formed to provide for the joint planning and operation of electric systems throughout New England. Under its long-range program, NEPOOL will enable each member utility to install fewer but larger, more efficient generating units and higher voltage transmission lines for the purposes of obtaining lower cost power and increased reliability.

A centralized dispatching facility ("NEPEX") is in operation as part of NEPOOL to insure reliability of service and to operate the most efficient available generating units of the member companies to fill the demands for power in the region. This concept is accomplished by use of computers to monitor and forecast load requirements and provide for economic dispatching.

NEPOOL is subject to proceedings pending before the FPC. In the course of these proceedings an administrative law judge has issued an initial decision dismissing a complaint filed by certain municipal

light departments and finding NEPOOL to be just and reasonable and in accord with the antitrust law and policy of the United States. The municipal light departments and the FPC staff have filed exceptions to this decision, which has been stayed pending final decision by the FPC.

The Company is also a member of the Northeast Power Coordinating Council ("NPCC"), an advisory organization which includes the major power systems in New England and New York plus the provinces of Ontario and New Brunswick in Canada. NPCC establishes criteria and standards for reliability and serves as a vehicle for coordination in the planning and operations of these systems to enhance reliability.

Future Generating Plant Commitments

The construction programs of NEPOOL members as presently planned for the period 1976 through 1988 include completion of two large oil-fired generating plants (including Unit No. 2) and nine nuclear plants. The Company or New Bedford has made commitments to participate as joint owner in certain of these units shown in the table below. The Company plans to purchase New Bedford's interest in such units in 1976 (see "Construction and Financing").

Unit	Type	Plant Capacity (MW)	Entitlement (MW)	Location	Scheduled Completion Date	Estimated Cost of Entitlement	Expenditures through June 30, 1976	Estimated Cost Per KW
						(In Thousands)		
Wyman No. 4	O	600	8	Yarmouth, Me.	1978	$ 2,678	$ 743	$ 335
Pilgrim No. 2	N	1,180	18	Plymouth, Mass.	1982	19,731	1,401	1,093
Seabrook Nos. 1 and 2	N	2,300	71	Seabrook, N.H.	1981-1983	49,900	1,316	703
NEP Nos. 1 and 2	N	2,300	100	Not Determined	1984-1986	81,781	908	818
Montague Nos. 1 and 2	N	2,300	103	Montague, Mass.	1986-1988	109,217	1,538	1,060

Type: N — Nuclear; O — Oil

The cost estimates and completion dates shown above reflect the latest information made available to the Company by the lead participant in each project. The estimated completion dates for all of the above-mentioned nuclear units reflect delays reported to date by the lead participants. Such delays have resulted in part from government licensing requirements and environmental controversies (see "Business — Environmental Matters"). Additional delays may require upward revision of construction cost estimates to give effect to inflationary cost increases during periods of deferral.

The Company expects to construct or acquire additional generating capacity in the future as may be necessary to meet the load growth requirements of the distribution subsidiaries of the Association.

Fuel Supply

Oil. The Company has entered into a contract with Nepco Terminal, Inc., a subsidiary of New England Petroleum Corporation, for the purchase of the total estimated requirements of residual fuel oil for Unit No. 1 and Unit No. 2. This contract expires on November 15, 1978 but may be extended by

mutual agreement of the parties to the contract. Oil is delivered by tanker at dock facilities constructed by the supplier on a site leased from the Company adjacent to the units. Fuel oil storage facilities at the site available to the Company have a capacity of 1,200,000 barrels, representing 36 days of normal operation of the two units. Some of these storage facilities are owned by the supplier and the remainder are jointly owned by the Company and Montaup and are made available to the supplier under a lease agreement. Since February 1, 1976, the date of commercial operation of Unit No. 2, the Company has maintained an average daily inventory of 537,000 barrels of fuel oil which represents 16 days of normal operation of the two units. This supply is maintained by tanker deliveries every seven to ten days.

Under the Emergency Petroleum Allocation Act of 1973, the Federal Energy Administration ("FEA") has the authority to regulate prices and allocate supply of fuel oil and certain other petroleum products. Effective June 1, 1976 the FEA removed all price and allocation controls with respect to residual (No. 6) fuel oil, which is the fuel used by the Company for substantially all of its generation. The Company cannot predict whether further Federal and state regulations may be imposed affecting the price or availability of fuel used by it. It is anticipated, however, that any allocation programs would recognize the essential service of public utilities.

Reference is made to "Management's Discussion and Analysis of the Statements of Income" for a discussion of the cost of fuel.

Nuclear Fuel. The supply of fuel for nuclear generating plants generally involves the acquisition of uranium concentrate, its conversion to uranium hexafluoride, enrichment of that gas, fabrication of the nuclear fuel assemblies, and reprocessing of the spent fuel. The Company has been informed by the lead participants for the units in which it will participate that there are outstanding contracts covering a portion of the above elements of the fuel cycle for such units extending through the years indicated below:

	Uranium Concentrate Purchases	Conversion to Hexafluoride	Enrichment	Fabrication	Reprocessing Service(a)
Pilgrim No. 2	(b)	1986	2010	1984	None
Montague No. 1	1985(c)	None	2014	1991	None
Montague No. 2	1987(c)	None	None	1993	None
Seabrook No. 1	1982(d)	1986	30(e)	4(f)	None
Seabrook No. 2	1982(d)	1986	30(e)	4(f)	None
NEPCO No. 1	None	None	30(e)	2(g)	None
NEPCO No. 2	None	None	30(e)	2(g)	None

(a) Currently there are no reprocessing facilities operating in the United States. Reprocessing can be delayed without adverse operational effects by the acquisition of additional storage capacity for spent fuel.

(b) Contractual entitlements exist for supplies of uranium ore sufficient to provide about 85% of the initial core to be placed in Pilgrim Unit No. 2 in late 1982. Options exist to purchase additional ore for delivery through 1984.

(c) The periods shown are those covered by the original uranium delivery schedules in the contracts. The uranium supplier has taken the position that it may no longer be obligated to deliver the uranium in view of the deferral of the units from their original schedule.

(d) 51% of the combined requirements for Seabrook Units No. 1 and 2 have been purchased for 1983.

(e) Number of years from first delivery for enrichment.

(f) Number of years from date of startup; fabrication service contracts exist for the first core and for three subsequent reload regions.

(g) Number of years from date of startup; fabrication service contracts exist for the first core and for one subsequent reload region.

To the extent necessary, the owners of nuclear generating plants in which the Company will participate will have to enter into supply contracts for additional uranium concentrate and contracts for other elements of the fuel cycle such as conversion and reprocessing. The price of nuclear fuel, its availability and the terms of future contracts cannot now be predicted.

Regulation

The Company is subject to regulation by the Massachusetts Department of Public Utilities as to issue of securities, accounting, and other matters. The Company is a "public utility" within the meaning of Part II of the Federal Power Act and is subject to regulation thereunder by the FPC as to rates and other matters and has filed its power contracts with the FPC as rate schedules.

In January 1976 the Company tendered for filing with the FPC initial rate schedules for the sale of power from Unit No. 2. On June 21, 1976, the FPC accepted the initial rate schedules for filing. Such rate schedules as set forth in the power contracts are subject to adjustment to give effect to the cost of capital resulting from the Company's financings in 1976. The FPC considers these adjustments as a change in rates requiring additional filing and acceptance. On August 13, 1976 the Company made an additional filing with the FPC with respect to such adjustments, which may be the subject of further proceedings. The town of Belmont, Massachusetts, the sole wholesale customer of Cambridge Electric, was permitted by the FPC to intervene in the initial proceedings.

Recent Massachusetts legislation has established an Energy Facilities Siting Council for the state. This legislation requires each electric company to file periodically with the Council long-range forecasts of the electric needs and requirements of its market area. To approve a long-range forecast, the Council must find, among other things, that the company's plans for construction of certain electric power generation facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth of Massachusetts. Construction of new electric facilities of the types enumerated above is prohibited after May 1, 1976, unless such facilities are consistent with a long-range forecast approved by the Council.

Public Power

A proposal for the establishment of a Massachusetts Power Authority will be on the ballot for the 1976 Massachusetts general election. If approved by the voters at such election, the proposal would become law. If established, the Authority would have as its primary purpose the provision of bulk power supply to the electric utilities of Massachusetts. The Authority would be authorized to build and operate all new generating and transmission facilities in Massachusetts and would have the option to acquire existing generating and transmission facilities by purchase or eminent domain. The commencement of construction by utilities in Massachusetts of any new facility would be prohibited after two years unless the Authority certifies that it is not capable of financing such facility and that such construction would be consistent with the purpose of the act.

The Company cannot now predict whether the proposal will become law, and if so what effect it will have upon its properties and operations.

Environmental Matters

The Company's generating facilities are the subject of federal, state and local environmental quality control regulations. With respect to Unit No. 1 and Unit No. 2, these regulations require the use of more expensive low sulphur fuels and have, in addition, required capital expenditures by the Company of approximately $14,000,000. The provisions of the Company's power contracts operate to recover such costs.

Environmental regulations governing site selection for new electric generating facilities and imposing air and water pollution standards requiring the installation of costly pollution control facilities have had and may be expected to continue to have an effect upon the capital costs and construction schedules of NEPOOL generating facilities (see "Business — Future Generating Plant Commitments"). The Company estimates that approximately 15% of the aggregate construction costs of jointly-owned units will be incurred to satisfy environmental regulations. These costs have been included in the construction estimates discussed under "Construction and Financing". Such expenditures are not expected to be material in 1976 and 1977. Increases in these costs cannot be predicted since the standards and the technology required to meet them are in a state of rapid change. There has been particular public controversy concerning development of nuclear energy. Despite the safety record of the nation's nuclear power plants, these plants have become the target of certain groups claiming, through litigation or intervention in regulatory proceedings, that the present state of nuclear technology presents unacceptable risks to public health and safety and to the environment. These claims may cause delays in, or interfere with, scheduled construction of new nuclear plants or operation of existing plants.

Employees

At June 30, 1976, the Company had 103 regular employees, of whom 68 were represented by the Utility Workers' Union of America, A.F.L.-C.I.O. The existing collective bargaining agreement expires May 31, 1977.

MANAGEMENT

Officers

The officers of the Company are appointed to serve until the next annual meeting of directors with the exception of the Treasurer and Clerk who are elected to serve until the next stockholder's meeting. The names of the executive officers of the Company and the office held by each are as follows:

Name	Age at June 30, 1976	Year of Election to Board	Positions and Offices Held with the Company
Gerald E. Anderson*	45	1973	Chairman of the Board and Director
George H. Gowdy*	65	1966	President and Director
Earl G. Cheney*	39	1975	Financial Vice President and Director
William R. Smith	54	1973	Vice President, General Manager and Director
John D. Heaton	34	—	Comptroller
Robert S. Parker	50	—	Treasurer
Michael P. Sullivan	27	—	Clerk

*Member of Executive Committee.

Directors

The directors of the Company are elected annually at the annual stockholder's meeting. The directors of the Company who are not also officers are as follows:

Name	Age at June 30, 1976	Year of Election to Board	Principal Occupation or Employment
Charles T. Abbott	70	1966	Retired Executive Vice President — NEGEA Service Corporation
Leland R. Crowell	67	1971	Retired Vice President and General Manager of the Company
Jeremiah V. Donovan	4?	1976	Vice President and General Manager — Cambridge Electric
Ronald F. MacDonald	46	1973	Executive Vice President and General Manager — New Bedford
Richard G. Velte	56	1975	Vice President, Engineering — NEGEA Service Corporation

All officers have been employed by the Company either in the capacities indicated or in other executive capacities for more than the last five years, except as follows. Prior to joining the Company in 1975 and for the previous five years, Mr. Heaton was employed by Arthur Andersen & Co. Mr. Sullivan was employed by NEGEA Service Corporation after graduating from law school in 1975 and was appointed Clerk of the Company effective September 1, 1976.

Each director who is not an officer of the Company has been employed by the companies listed above in the capacity indicated or in other capacities for more than five years.

Remuneration of Directors and Officers

No direct remuneration in excess of $40,000 was paid by the Company to any director or officer during the year 1975. All directors and officers of the Company as a group were paid an aggregate of $35,050 by the Company during the year 1975. No director, as such, is eligible for either the Company's pension plan or the Employees' Savings Plan.

No remuneration is paid by the Company to M[illegible]n, Cheney, Gowdy, Heaton, Sullivan or Parker. Their compensation is paid by NEGEA Service Corporation, an affiliated service company, of which they are officers and employees. For the year 1975, approximately 7% of the officers' salaries was charged by the service corporation to the Company.

Ownership of Equity Securities

All of the common stock of the Company is owned by the Association. The directors and officers of the Company, as a group, owned beneficially 9,101.7 common shares of the Association at March 1, 1976, which represented less than one percent of the total common shares outstanding.

Certain Transactions

The Company has received short-term advances from the Association to temporarily finance a portion of the construction of Unit No. 2.

As described under "Business — Power Contracts" the Company has entered into long-term power contracts with two of its affiliates for the sale of power from Unit No. 1 and Unit No. 2. Sales of power to affiliates for the five years ended December 31, 1975 and the twelve months ended June 30, 1975 are shown in the Statements of Income.

Payments to NEGEA Service Corporation, an affiliated company which performs management, accounting, engineering and other services at cost plus a return on equity of 10% per annum, for the three years ended December 31, 1975 amounted to \$303,000, \$399,000 and \$603,000, respectively. The Company believes that such amounts are at least as favorable to it as those which would be charged by an independent third party.

Reference is made to "Construction and Financing" and "Business — Future Generating Plant Commitments" for a discussion of the Company's plan to purchase certain properties of New Bedford at New Bedford's cost.

DESCRIPTION OF SERIES B BONDS

General

The Series B Bonds will be issued under a First and General Mortgage Indenture (the "Indenture"), to be dated as of September 1, 1976 between the Company and Citibank, N.A., Trustee. The Company has \$10,000,000 of outstanding short-term loans from Citibank, which are to be repaid from the proceeds of its 1976 financings. The Series B Bonds will be the first series of bonds issued under the Indenture.

The Company has outstanding a series of First Mortgage Bonds, Series A, 7%, Due 1996 (the "Series A Bonds") issued under and secured by an Indenture of Trust and First Mortgage dated as of October 1, 1968 between the Company and State Street Bank and Trust Company, Trustee (the "1968 Indenture"), which were issued in 1968 to finance the construction of Unit No. 1. The lien of the 1968 Indenture is prior to the lien of the Indenture with respect to certain property of the Company, principally Unit No. 1 (see "Security" herein). The 1968 Indenture permits the issuance of additional bonds for the limited purpose of financing additions to Unit No. 1, but the Company will covenant in the Indenture that so long as the Series B Bonds or any other bonds issued under the Indenture are outstanding, it will not issue further bonds under the 1968 Indenture. The Company will covenant in the Indenture to obtain the release and discharge of the lien of the 1968 Indenture as soon as practicable after it satisfies all of its obligations thereunder including the payment of all outstanding Series A Bonds. The Indenture will contain a covenant that the Company will pay or cause to be paid the Series A Bonds in accordance with their terms and will faithfully perform all the terms, covenants and conditions to be performed by the Company under the 1968 Indenture.

A copy of the Indenture is filed with the Securities and Exchange Commission as an Exhibit to the Registration Statement of which this Prospectus is a part, and is incorporated herein by reference. The following statements relating to the Series B Bonds and the Indenture are subject to and are qualified by the detailed provisions of the Indenture, particularly the parts thereof specifically re-

ferred to. Terms under this heading which are printed in initial capital letters are defined in the Indenture and are given such defined meanings when used under this heading. A copy of the 1968 Indenture is also an exhibit to the Registration Statement and is also incorporated herein by reference. The following statements with respect to the 1968 Indenture are subject to and are qualified by the detailed provisions of the 1968 Indenture, particularly the parts thereof specifically referred to.

Series B Bonds

The Series B Bonds will mature September 1, 2006. Interest on the Series B Bonds, at the rate per annum shown on the cover page of this Prospectus, will accrue from the date of original issue and will be payable semi-annually on each March 1 and September 1 to the persons in whose names the Series B Bonds are registered at the close of business on each February 15 or August 15 prior to the payment date. Principal and interest are payable at the corporate trust office of the Trustee in New York City. Checks for interest payments will be mailed to the registered holders entitled thereto. The Series B Bonds will be issued in fully registered form without coupons in denominations of $1,000 or multiples thereof. No service charge will be made for any transfer or exchange of Series B Bonds.

The Series B Bonds may be redeemed in whole or in part (in multiples of $1,000) prior to maturity, upon at least 30 days' notice, at the applicable redemption price specified below, plus accrued interest to the date fixed for redemption. The applicable redemption prices are:

(i) the "Special Redemption Price" (expressed as a percentage of the principal amount of the bonds being redeemed) in effect during the twelve-month period beginning on the applicable September 1, as specified below, if the bonds are redeemed through the operation of the sinking and improvement fund described below, or by the use of certain insurance, condemnation, release or other moneys held by the Trustee as described below, or

(ii) otherwise the "General Redemption Price" (expressed as a percentage of the principal amount of the bonds being redeemed) in effect during the twelve-month period beginning on the applicable September 1, as specified below:

	General Redemption Price	Special Redemption Price		General Redemption Price	Special Redemption Price
1976	109.91%	101.055%	1991	104.79%	100.83%
1977	109.57	101.05	1992	104.45	100.80
1978	109.23	101.04	1993	104.10	100.77
1979	108.89	101.03	1994	103.76	100.74
1980	108.54	101.02	1995	103.42	100.70
1981	108.20	101.01	1996	103.08	100.66
1982	107.86	101.00	1997	102.74	100.62
1983	1[illegible].52	100.99	1998	102.40	100.57
1984	107.18	100.97	1999	102.05	100.52
1985	106.84	100.96	2000	101.71	100.46
1986	106.49	100.94	2001	101.37	100.40
1987	106.15	100.92	2002	101.03	100.34
1988	105.81	100.90	2003	100.69	100.26
1989	105.47	100.88	2004	100.35	100.18
1990	105.13	100.86	2005	100.00	100.00

No Series B Bonds may be redeemed at the General Redemption Price prior to September 1, 1986, directly or indirectly, from the proceeds of or in anticipation of any refunding operation involving the incurring of debt which has an interest cost to the Company, computed in accordance with generally accepted financial practices, of less than the stated interest rate per annum of the Series B Bonds.

The Company is required to redeem all outstanding bonds in the event that all or substantially all of the mortgaged and pledged property is destroyed or taken by eminent domain, and, under certain circumstances, to apply to the redemption of bonds insurance or other proceeds from the complete or substantially complete destruction or taking of a Substantial Unit (see "Covenants Relating to Substantial Units" herein). The Company is also permitted to apply to the redemption of bonds insurance and release proceeds and other moneys deposited with the Trustee and not withdrawn by the Company. All such redemptions of Series B Bonds will be at the applicable Special Redemption Price.

Security

The Series B Bonds will be secured by the Indenture equally and ratably with other bonds hereafter issued under the Indenture. The principal security for the bonds will be a lien on all the property now owned by the Company adjacent to the Cape Cod Canal in Sandwich, Massachusetts ("the Canal Site"), subject to certain Permitted Liens; a lien on all property, electric generating plants or interests therein hereafter acquired by the Company; and the assignment of certain Pledged Contracts, all of which are summarized as follows:

Lien on the Canal Site. The lien of the Indenture will include all the property of the Company now owned at the Canal Site, including Unit No. 1 and the Company's undivided one-half ownership interest in Unit No. 2, together with all properties and rights, permits, franchises and easements appurtenant thereto. The lien on Unit No. 1 is subject to the prior lien of the 1968 Indenture, and the lien on Unit No. 2 is subject to the interests of Montaup Electric Company under the Unit II Joint Venture Documents between the Company and Montaup, which provide, among other things, for the lease of a portion of the Canal Site for the use of Unit No. 2, the operation of Unit No. 2 and the common use of facilities and the sharing of related costs between Unit No. 1 and Unit No. 2. Upon the discharge of the 1968 Indenture, the lien of the Indenture will constitute a first lien upon all of the Company's property at the Canal Site.

Lien on After-Acquired Property. The lien of the Indenture will include all land, interests in land, real estate, physical assets, other property and interests in property and franchises hereafter acquired by the Company, whether tangible or intangible and wherever located, and all rights and interests of the Company appurtenant thereto, whether rights exclusive to the Company or shared in common with others.

Pledged Contracts. The Company will assign to the Trustee under the Indenture all of its right, title and interest (subject to its obligations) in, (a) the Unit II Joint Venture Documents, (b) the contracts for the sale of the power of Unit No. 1 (subject to the lien of the 1968 Indenture) and of the Company's one-half share of the power of Unit No. 2, and (c) the contract for the supply of oil to Unit No. 1 (subject to the lien of the 1968 Indenture) and to Unit No. 2. The Company is further obligated to assign to the Trustee from time to time all its right, title and interest in any contract to which it may become a party in the future having an initial term of

more than one year and relating to (i) the construction, ownership and operation of electric generating units in which the Company has an ownership interest, (ii) the supplying of fuel for any such unit, and (iii) the sale of the Company's share of the capacity and energy of any such unit.

Covenants Relating to Substantial Units

The Indenture will contain certain special provisions relating to Substantial Units. A Substantial Unit is defined in the Indenture as the Company's ownership interest in any electric generating unit the net book value (cost less depreciation) of which constitutes at least 25% of the net book value of the Company's ownership interests in all electric generating units (or 10% of such net book value in the case of a unit whose rated capacity constitutes at least 25% of the total rated capacity of the Company's interest in all electric generating units). So long as the Series A Bonds are outstanding, Unit No. 1 is not considered in determining whether another unit is a Substantial Unit. Unit No. 1 and Unit No. 2 are presently Substantial Units, but either or both may cease to be so in the future as the Company acquires ownership interests in additional electric generating units.

The provisions relating to Substantial Units are as follows:

(a) The Company is required to keep each Substantial Unit insured at all times against all property risks for which insurance is available from reputable insurance companies, and to obtain war risk insurance for each Substantial Unit if and whenever available. In the case of Unit No. 1 and Unit No. 2, such insurance must be in an amount at least equal to reproduction cost new less depreciation. In the case of other Substantial Units, if any, such insurance must be in an amount at least equal to net book value. If any Substantial Unit is completely or substantially completely destroyed or taken by eminent domain, the insurance proceeds or the proceeds from such taking must be applied to the redemption of outstanding bonds (pro rata among different series) if the amount of such proceeds exceeds 10% of the aggregate principal amount of bonds then outstanding. In the case of Series B Bonds, any such redemption will be at the applicable sinking fund redemption prices set forth in this Prospectus under "Special Redemption Price".

(b) So long as Unit No. 2 is a Substantial Unit, the Company may not voluntarily cancel or terminate the Unit II Joint Venture Documents or its contract with New Bedford and Cambridge Electric for the sale of the Company's one-half share of the net capability of Unit No. 2 (see "Business — Power Contracts"), nor may the Company voluntarily modify or amend the terms of the Unit II Joint Venture Documents or such power contract in any material respect without the written consent of the Trustee, which consent shall be granted if and only if (i) the holders of 66⅔% in principal amount of the bonds then outstanding consent thereto, or (ii) the Company delivers to the Trustee an opinion from an independent organization of national reputation acceptable to the Trustee engaged in providing financial and engineering consulting services to electric utility companies to the effect that such proposed modification or amendment does not materially adversely affect the rights of the holders of the bonds. Similar limitations on the Company's right to terminate or modify the power contracts for the sale of the capability of Unit No. 1 will be applicable under the Indenture after the Series A Bonds cease to be outstanding so long as Unit No. 1 is a Substantial Unit.

(c) The Company is required to have in effect at all times power contracts in good standing terminating not less than one year in the future providing for the sale of at least 75% of the aggregate net capability of Substantial Units. If the Company should in the future engage in the sale of electric power at retail, the requirement will apply instead to the total capability, including

purchased power, available to the Company for sales at wholesale if such total is less than the aggregate net capability of Substantial Units. The requirement will cease to apply entirely if the total capability available to the Company for sales at wholesale becomes less than one-third of the aggregate net capability of Substantial Units.

Renewal and Replacement Fund

The Indenture will provide that on or before June 1 in each calendar year commencing in 1977, the Company will, as and for a renewal and replacement fund, (a) deposit with the Trustee a sum of money and/or (b) allocate Available Bonds theretofore paid at maturity, redeemed or acquired by the Company and/or (c) allocate a Net Amount of Bondable Property, in an amount equal to 2¼% of the average gross plant investment in depreciable utility property on the books of the Company on January 1 and December 31 of each calendar year. For the calendar year 1976 the renewal and replacement fund will be equal to one-third of 2¼% of the average gross plant investment in depreciable utility property on the books of the Company on September 1 and December 31, 1976.

Unit No. 1 as constituted at the date of the 1968 Indenture is not included in depreciable utility property for purposes of computing the amount of the renewal and replacement fund so long as any Series A Bonds are outstanding. The Series A Bonds are entitled to the benefit of a cash sinking fund designed to retire the Series A Bonds over the remaining depreciable life of Unit No. 1.

Sinking and Improvement Fund

The Indenture will provide that prior to September 1 in each year the Company will deposit or set aside, as and for a sinking and improvement fund, an amount equal to 1% of the aggregate principal amount of bonds issued under the Indenture (with certain adjustments). The Company may satisfy this requirement by (i) depositing cash with the Trustee, (ii) crediting an amount equal to 60% of a Net Amount of Bondable Property, or (iii) crediting an amount of Available Bonds theretofore paid at maturity, redeemed or acquired by the Company. If cash is deposited with the Trustee, the Trustee will use such cash to redeem outstanding bonds (pro rata among different series), in the case of Series B Bonds at the applicable sinking fund redemption prices set forth in this Prospectus under "Special Redemption Price", plus accrued interest to the date of redemption.

Dividend Restriction

The Company will covenant in the Indenture that so long as any Series B Bonds are outstanding it will not pay or declare any dividends on its common stock (other than dividends payable in common stock) or make any distribution on, or purchase or otherwise acquire for value, any shares of its common stock (such actions being hereinafter referred to as "dividends on its common stock") in an amount which, together with all other dividends on its common stock declared within the period from January 1, 1976 to and including the date of such dividend declaration exceeds the sum of $6,000,000, plus, or minus if a deficit, the Net Income Available for Dividends on Common Stock for the period from January 1, 1976 to a date not more than 45 days prior to the date of such dividend declaration.

Issuance of Additional Bonds

Additional bonds may be issued under the Indenture in an unlimited amount upon compliance with the conditions set forth therein, (i) to the extent of 60% of a Net Amount of Bondable Property, (ii) to refund Available Series A Bonds under the 1968 Indenture, Available Bonds under the Indenture,

or Available Underlying Bonds and (iii) against the deposit of cash with the Trustee equal to the aggregate principal amount of bonds to be issued. Money deposited pursuant to (iii) above may be withdrawn to the extent of Available Bonds, Available Series A Bonds, Available Underlying Bonds or 60% of a Net Amount of Bondable Property.

No additional bonds may be issued under the Indenture (except bonds issued to refund bonds issued under the Indenture, Series A Bonds or Underlying Bonds which, in any such case mature within two years before or after the date of issue of the bonds to be so issued or which bear interest at a rate higher than the rate of interest to be borne by the bonds to be so issued) unless, for a period of 12 consecutive calendar months during the period of 15 calendar months next preceding the application for authentication of the bonds to be so issued, the Net Earnings of the Company (not more than 15% of which may be derived from securities, sources not part of the property mortgaged under the Indenture and mortgaged property leased to others which is not used for utility purposes) shall have been at least equal to twice the interest for one year upon all bonds outstanding under the Indenture at the date of such authentication (excluding any bonds for the retirement of which provision has been made), the bonds to be so issued, and all other indebtedness for money borrowed then secured by a lien equal or superior to the lien of the Indenture (excluding any such indebtedness for the payment or the redemption of which the necessary moneys shall have been deposited with the trustee or mortgagee under the mortgage securing the same). Net Earnings of the Company means the net income of the Company, with certain adjustments, plus income taxes and interest expense.

Additional Funded Debt

The Indenture will provide that, so long as the Company is a subsidiary of the Association or another holding company as defined in the Public Utility Holding Company Act of 1935, the Company will not incur, assume or guarantee any indebtedness maturing more than one year after the date thereof if immediately thereafter the total of such indebtedness of the Company would exceed the total of the Company's capital stock, capital surplus and retained earnings accounts.

Release and Substitution of Property

The Indenture will provide that subject to various limitations property may be released from the lien thereof on a sale or other disposition upon the deposit with the Trustee of cash, obligations or Bondable Property equal to the Current Fair Value of the property released. Release moneys held by the Trustee may be withdrawn by the Company for or on account of a Net Amount of Bondable Property or in connection with the payment, redemption or other discharge of Available Bonds, Available Series A Bonds or Available Underlying Bonds.

The Indenture will also provide that the Company may grant to others, free from the lien of the Indenture, rights of way, rights of common use and easements in respect of the mortgaged and pledged property for the benefit of any one or more electric generating units if, in the opinion of the Company's Board of Directors, (i) the transaction is in accordance with good utility practice, (ii) the consideration received or to be received in respect thereof is of a value to the Company at least equal to the interest being granted, and (iii) the transaction will not materially adversely affect the continued operation of the trust estate or the security under the Indenture viewed as a whole. The Company is required to assign to the Trustee any contract providing for the payment of consideration for interests so granted.

Indenture Amendments

Any provision of the Indenture may be amended, eliminated or modified, with the consent of the holders of not less than 66⅔% of bonds then outstanding thereunder (or if less than all the series are affected, with the consent of the holders of not less than 66⅔% in principal amount of each series so affected). No such modification or amendment may (a) affect the amount, time or terms of payment of the principal of or premium or interest on any bond without the written consent of the holder of each bond so affected; (b) change the percentage of bondholders required to effect such modification or permit the creation of any lien, not otherwise permitted, prior to or on a parity with the lien of the Indenture, without the consent of the holders of all the bonds then outstanding; or (c) modify, without the written consent of the Trustee, the rights, duties or immunities of the Trustee.

Defaults

The Indenture will provide that any of the following will constitute an event of default thereunder: failure to pay interest for 60 days or principal when due; failure to satisfy any required sinking, purchase, amortization, improvement or other fund payment for 90 days; the occurrence of an event of default under the 1968 Indenture; failure to maintain the required insurance on any Substantial Unit; failure to perform any other covenants of the Company for a period of 90 days after written notice; and certain events of bankruptcy, insolvency, dissolution or liquidation. The Company is required to furnish to the Trustee an annual Officers' Certificate as to whether or not any defaults exist under the Indenture.

The holders of a majority in principal amount of outstanding bonds may waive any past default except a default in the payment of the principal of or premium or interest on any bond or a default with respect to any covenant in the Indenture which cannot be modified without the consent of the holder of each outstanding bond affected. The holders of a majority in principal amount of outstanding bonds may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee. The Trustee is not required to advance or risk its own funds or otherwise incur financial liability in the performance of any of its duties if there are reasonable grounds for believing that repayment is not reasonably assured to it under the terms of the Indenture.

Certain Defined Terms

Bondable Property means any property acquired or constructed by the Company after October 31, 1968, used or planned to be used in the production or furnishing or both of electricity, gas, water or steam and properly chargeable to the Company's plant or plant addition accounts. Bondable Property may include construction work in progress and interests of the Company in property owned jointly or in common with other parties, improvements to public ways paid for by the Company although title thereto may not be in the Company, and movable physical property of the Company situated on land leased by the Company; but does not include (except in certain specified circumstances) real estate unless owned in fee simple or interests in real estate unless owned in perpetuity, property excluded from the lien of the Indenture or property subject to a lien (other than a Permitted Lien) prior to or on a parity with the lien of the Indenture. Property additions to Unit No. 1 since the date of the 1968 Indenture are Bondable Property even though subject to the Prior Lien of the 1968 Indenture.

Amount of Bondable Property means the Cost or Current Fair Value, whichever is less, of Bondable Property evidenced to the Trustee, less in the case of Bondable Property which was subject to an Underlying Mortgage 166⅔% of the principal amount of the Underlying Bonds outstanding at the time of acquisition of such Bondable Property.

Net Amount of Bondable Property means the Amount of Property remaining after deducting the Amount of Bondable Property (i) constructed or acquired with certain proceeds of insurance paid to the Company, (ii) constructed or acquired with the net proceeds received from certain dispositions of property, (iii) allocated to satisfy the renewal and replacement fund and the sinking and improvement fund, or (iv) allocated or used as a basis of credit under the 1968 Indenture or any Underlying Mortgage; and also after deducting any Excess of Retirements (the excess of retirements over the requirements of the renewal and replacement fund) and the Net Amount of Bondable Property theretofore used or allocated under the Indenture.

Underlying Bonds means obligations secured by an Underlying Mortgage which term includes any mortgage other than the 1968 Indenture and a purchase money mortgage existing on Bondable Property at the time of its acquisition by the Company which is a Prior Lien, but only if the Cost or Fair Value, whichever is less, of such property is at least equal to 166⅔% of the principal amount of the obligations secured by such Underlying Mortgage, all other Prior Liens on such property except for Permitted Liens have been discharged and the lien of such Underlying Mortgage does not constitute a lien on any other property of the Company. The Company will covenant not to become liable for any Underlying Bonds if the principal amount of all Underlying Bonds outstanding would thereupon exceed 25% of the sum of the principal amount of all outstanding Series A Bonds, bonds issued under the Indenture, and Underlying Bonds.

Annual Reports to Security Holders

Upon request, the Company will furnish an annual report, including certified financial statements, to any holder of the Series B Bonds.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Canal Electric Company:

We have examined the balance sheet of Canal Electric Company (a Massachusetts corporation and wholly-owned subsidiary of New England Gas and Electric Association) as of December 31, 1975, and the related statements of income (included elsewhere in this Prospectus), retained earnings, and sources of funds used for construction for the five years 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.

In our opinion, the financial statements referred to above present fairly the financial position of Canal Electric Company as of December 31, 1975, and the results of its operations and its sources of funds used for construction for the five years then ended, in conformity with generally accepted accounting principles consistently applied during the periods.

Arthur Andersen & Co.

Boston, Massachusetts,
February 17, 1976.

CANAL ELECTRIC COMPANY

BALANCE SHEETS

ASSETS

	December 31, 1975	June 30, 1976 (Unaudited)
	(Dollars in Thousands)	
PROPERTY, PLANT AND EQUIPMENT, at original cost	$ 67,247	$126,385
Less — Accumulated depreciation	15,456	17,500
	51,791	108,885
Construction work in progress	57,398	1,041
	109,189	109,926
CURRENT ASSETS:		
Cash (Note 2)	7,938	8,219
Accounts receivable —		
Affiliated companies	2,845	3,925
Other	6,977	7,818
Electric production fuel oil	543	663
Prepaid property taxes and other	842	698
	19,145	21,323
DEFERRED CHARGES	183	239
	$128,517	$131,488

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

CANAL ELECTRIC COMPANY

BALANCE SHEETS

STOCKHOLDER'S EQUITY AND LIABILITIES

	December 31, 1975	June 30, 1976 (Unaudited)
	(Dollars in Thousands)	
CAPITALIZATION:		
Common Equity (Note 3) —		
Common stock, $25 par value —		
Authorized — 1,523,200 shares		
Outstanding — 748,200 shares at December 31, 1975 and 921,900 shares at June 30, 1976, wholly owned by the Association	$ 18,705	$ 23,048
Amounts paid in excess of par value	695	2,404
Retained earnings	6,552	6,844
	25,952	32,296
Long-term debt (Note 2)	18,279	17,897
	44,231	50,193
CURRENT LIABILITIES:		
Interim Financing (Note 2) —		
Notes payable to banks	64,600	62,300
Notes payable to the Association	3,600	2,350
	68,200	64,650
Other Current Liabilities —		
Current sinking fund requirements	898	291
Accounts payable	5,996	5,805
Accrued taxes	811	144
Accrued interest and other	363	339
	8,068	6,579
	76,268	71,229
DEFERRED CREDITS:		
Accumulated deferred income taxes	6,610	7,610
Unamortized investment tax credits	1,408	2,456
	8,018	10,066
COMMITMENTS (Note 5)		
	$128,517	$131,488

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

CANAL ELECTRIC COMPANY

STATEMENTS OF SOURCES OF FUNDS USED FOR CONSTRUCTION

	Year Ended December 31,					Twelve Months Ended June 30,
	1971	1972	1973	1974	1975	1976
	(Dollars in Thousands)					(Unaudited)
Sources of Funds —						
Operations:						
Net income	$ 2,104	$ 2,151	$ 2,339	$ 2,856	$ 3,829	$ 3,971
Items not requiring or (providing) funds:						
Depreciation	2,064	2,161	2,282	2,325	2,367	3,234
Deferred income taxes	635	913	1,464	895	608	1,117
Investment tax credits, net	[illegible]	(41)	82	(22)	7	1,089
Allowance for funds used during construction	(151)	(299)	(921)	(2,702)	(4,125)	(2,570)
Funds from Operations	4,597	4,885	5,246	3,352	2,686	3,841
Financing:						
Notes payable to banks, net	5,150	8,150	18,550	13,400	17,650	4,950
Notes payable to the Association, net	—	—	—	5,000	(1,400)	(2,050)
Sale of common stock	—	—	—	—	—	6,052
Funds from Financing	5,150	8,150	18,550	18,400	16,250	8,952
Other Sources (Uses) of Funds:						
Changes in working capital (exclusive of interim financing):						
Cash and accounts receivable	(211)	(2,852)	(3,050)	(4,849)	(3,948)	(4,768)
Accounts payable	385	69	1,019	3,390	452	672
Other	(340)	254	(467)	(385)	380	(147)
Redemptions of stock	(1,997)	(892)	(954)	(954)	(954)	(477)
Payment of dividends	(2,011)	(1,809)	(1,504)	(824)	(832)	(2,078)
Retirement of long-term debt through sinking funds	(967)	(967)	(961)	(960)	(1,357)	(1,361)
Other, net	32	18	(146)	(175)	47	(26)
Other Sources (Uses) of Funds	(5,109)	(6,179)	(6,063)	(4,757)	(6,212)	(8,185)
	$ 4,638	$ 6,856	$17,733	$16,995	$12,724	$ 7,608
Funds Used for Construction —						
Unit No. 1	$ 3,905	$ 2,096	$ 1,089	$ 1,588	$ 1,090	$ 147
Unit No. 2	884	5,059	17,565	18,109	15,759	9,123
Joint Ownership Projects	—	—	—	—	—	908
	4,789	7,155	18,654	19,697	16,849	10,178
Less — Allowance for funds used during construction	151	299	921	2,702	4,125	2,570
	$ 4,638	$ 6,856	$17,733	$16,995	$12,724	$ 7,608

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

CANAL ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31, 1971	1972	1973	1974	1975	Twelve Months Ended June 30, 1976
	(Dollars in Thousands)					(Unaudited)
Balance at beginning of period	$ 253	$ 346	$ 688	$ 1,523	$ 3,555	$ 4,951
Add — Net income	2,104	2,151	2,339	2,856	3,829	3,971
	2,357	2,497	3,027	4,379	7,384	8,922
Deduct — Cash dividends on common stock	2,011	1,809	1,504	824	832	2,078
Balance at end of period (Note 3)	$ 346	$ 688	$ 1,523	$ 3,555	$ 6,552	$ 6,844

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

CANAL ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

(Including Notes Applicable to Unaudited Period)

1. Accounting Policies

Transactions with Affiliates

The Company is a wholly-owned subsidiary of New England Gas and Electric Association. The Association is an exempt holding company under the provisions of the Public Utility Holding Company Act of 1935 and, in addition to its investment in the Company, has interests in other utility companies and a service company.

Transactions between the Company and other system companies include purchase and sale of electricity and payment for management, accounting, engineering and other services rendered by the service company. Transactions with other system companies are subject to review by the Federal Power Commission and the Massachusetts Department of Public Utilities.

Depreciation

Depreciation is provided using the straight-line method at rates intended to amortize the original cost of properties over their estimated lives. The Company's composite depreciation rate, based on average depreciable property in service, was 3.6% for the years 1971 through 1975 and for the twelve months ended June 30, 1976.

Maintenance

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

Allowance for Funds Used During Construction ("AFUDC")

The Company reflects as an element of the cost of construction of depreciable property an allowance for funds (including common equity funds) employed during periods when property is under construction. An amount equal to the AFUDC capitalized in the current period, while not currently providing funds, is reflected as Other Income. Under applicable rate making principles, property under construction is not included in rate base on which the Company is permitted to earn a return. Amounts so capitalized are included in rate base when property is placed in service, and these amounts are recoverable in revenues over the service life of the constructed property.

2. Long-term Debt and Interim Financing

Long-term debt outstanding, including premiums, is as follows:

	December 31, 1975	June 30, 1976
	(Dollars in Thousands)	
First Mortgage Bonds, Series A, 7%, Due 1996	$18,820	$18,188
Bank Term Loan	357	—
Less current sinking fund requirements	(898)	(291)
Total Long-term Debt	$18,279	$17,897

2. **Long-term Debt and Interim Financing — (Continued)**

The Series A Bonds require sinking fund payments of $760,000 annually through 1996. The balances of long-term debt outstanding at December 31, 1975 and June 30, 1976 are exclusive of $219,000 and $469,000 principal amounts of Series A Bonds purchased by the Company and deposited with the indenture trustee in anticipation of future sinking fund requirements. The Company may in the future continue to purchase its outstanding long-term debt under favorable conditions.

Notes Payable to Banks

The Company's short-term borrowings from banks are unsecured and are evidenced by notes payable which are due within one year. Interest rates are based upon the banks' prime rates on the date notes are originated or renewed. The weighted average interest rate for loans outstanding was 7.9% at December 31, 1975 and 7.6% at June 30, 1976. The monthly average of notes payable outstanding during 1975 was $57,796,000 at a weighted average interest rate of 8.4%, with a maximum amount outstanding of $67,050,000 at November 30, 1975. For the twelve month period ended June 30, 1976, the monthly average of notes outstanding was $64,204,000 at a weighted average interest rate of 8.2%, with a maximum amount outstanding of $68,850,000 at April 30, 1976. The Company intends to repay outstanding notes with the proceeds from sales of long-term debt and equity securities (see "Construction and Financing").

Compensating Balances

In connection with its short-term financing arrangements, the Company has understandings with the banks from which it has borrowings that it will maintain average cash balances determined from the banks' records equal to a percentage of borrowings outstanding. Generally, the banks required a 20% compensating balance during 1975 and through June 30, 1976. At some banks, the Company pays interest at the effective borrowing rate in lieu of maintaining the full bank balances required.

Cash on deposit by the Company at banks where it had outstanding borrowings totaled $7,900,000 at December 31, 1975 and $8,000,000 at June 30, 1976, substantially all of which was intended to meet compensating balance requirements. There are no legal restrictions on withdrawal of these funds.

Notes Payable to the Association

The Company had short-term notes payable to the Association totaling $3,600,000 at December 31, 1975 and $2,350,000 at June 30, 1976. These notes are written for a term of eleven months and twenty-nine days. Interest is at the prime rate (7¼% at June 30, 1976) and is adjusted for changes in the rate during the term of the notes.

3. Common Equity

Common Stock

During the period 1971 through June 30, 1976, the Company repurchased or issued shares of its common stock as follows:

Year	Number of Shares (Repurchased) Issued	Amount Charged (Credited) to Common Stock $25 Par Value	Amounts Paid in Excess of Par Value
		(Dollars in Thousands)	
1971	(77,000)	$1,925	$ 72
1972	(34,400)	860	32
1973	(36,800)	920	34
1974	(36,800)	920	34
1975	(36,800)	920	34
1976	173,700	(4,343)	(1,709)

Retained Earnings

The terms of the indenture securing the Series A Bonds and an order of the Massachusetts Department of Public Utilities contain a restriction which provides that dividends may not be paid on common stock of the Company if such dividend would reduce the equity capital of the Company below the total amount of long-term debt outstanding. At June 30, 1976, none of the retained earnings was restricted against payment of cash dividends on common stock.

4. Pensions and Employee Benefits

The Company has a noncontributory pension plan covering substantially all regular employees who have attained the age of 25. Total pension costs include amounts sufficient to amortize prior service costs over 15 years. Pension costs are funded as accrued.

Effective December 1, 1975, the Company amended its pension plan and certain of its other employee benefit plans. The amendments to the pension plan, which include changes in eligibility requirements and various other pension plan improvements, required adoption of a different actuarial cost method and changes in certain actuarial assumptions. These changes are expected to have the effect of increasing annual pension expense for 1976 and subsequent years, but the aggregate of employee benefit expense is not expected to increase significantly as a result of these changes.

The Company also has an Employees Savings Plan which provides for company contributions equal to contributions by eligible employees but not in excess of 4% of each employee's compensation rate.

4. **Pensions and Employee Benefits — (Continued)**

The cost of these plans was as follows:

	Year Ended December 31,					Twelve Months Ended June 30,
	1971	1972	1973	1974	1975	1976
	(Dollars in Thousands)					(Unaudited)
Pension Plan	$ 39	$ 41	$ 75	$ 84	$ 79	$ 81
Savings Plan	23	25	32	35	40	41
	$ 62	$ 66	$107	$119	$119	$122

5. **Commitments**

Rents and Leases

The Company leases certain facilities and equipment used in its operations. Rent expense under these leases was $836,000, $1,086,000, $1,084,000, $843,000 and $960,000 for the years 1971 through 1975 and $951,000 for the twelve months ended June 30, 1976.

Future minimum commitments under non-cancellable leases total $1,497,000 payable approximately $500,000 per year through 1978.

Construction

The Company has made substantial commitments in connection with its construction program. Construction expenditures for the four years ending December 31, 1980 are estimated at $80,100,000 (see "Construction and Financing").

6. **Quarterly Information**

Unaudited quarterly information pertaining to the results of operations for the six months ended June 30, 1976 may be found under "Management's Discussion and Analysis of the Statements of Income" elsewhere in this Prospectus.

UNDERWRITING

The Underwriters named below have severally agreed to purchase from the Company the following respective principal amounts of the Series B Bonds:

Underwriter	Principal Amount
The First Boston Corporation	$ 7,100,000
Advest Co.	550,000
Bache Halsey Stuart Inc.	1,050,000
Bear, Stearns & Co.	925,000
Blyth Eastman Dillon & Co. Incorporated	1,050,000
Burgess & Leith	350,000
Dillon, Read & Co. Inc.	1,050,000
Dominick & Dominick, Incorporated	550,000
Drexel Burnham & Co. Incorporated	1,050,000
Fahnestock & Co.	350,000
First Albany Corporation	350,000
Goldman, Sachs & Co.	1,050,000
Hornblower & Weeks-Hemphill, Noyes Incorporated	1,050,000
E. F. Hutton & Company Inc.	1,050,000
Kidder, Peabody & Co. Incorporated	1,050,000
Kuhn, Loeb & Co.	1,050,000
Lehman Brothers Incorporated	1,050,000
Loeb, Rhoades & Co.	1,050,000

Underwriter	Principal Amount
Merrill Lynch, Pierce, Fenner & Smith Incorporated	$ 1,050,000
Moseley, Hallgarten & Estabrook Inc.	550,000
Paine, Webber, Jackson & Curtis Incorporated	1,050,000
Wm. E. Pollock & Co., Inc.	550,000
R. W. Pressprich & Co. Incorporated	550,000
Reynolds Securities Inc.	1,050,000
L. F. Rothschild & Co.	925,000
Salomon Brothers	1,050,000
Shearson Hayden Stone Inc.	925,000
Spencer Trask & Co. Incorporated	550,000
Stuart Brothers	550,000
Tucker, Anthony & R. L. Day, Inc.	550,000
Burton J. Vincent, Chesley & Co.	350,000
Warburg Paribas Becker Inc.	1,050,000
Weeden & Co. Incorporated	925,000
Dean Witter & Co. Incorporated	1,050,000
Wood, Struthers & Winthrop Inc.	550,000
Total	$35,000,000

The Underwriting Agreement provides that the obligations of the Underwriters are subject to certain conditions precedent, and that the Underwriters will be obligated to purchase all of the Series B Bonds if any are purchased.

The Company has been advised by The First Boston Corporation, as Representative of the Underwriters, that the Underwriters propose to offer the Series B Bonds to the public initially at the offering price set forth on the cover page of this Prospectus and, through the Representative, to certain dealers at such price less a concession of ½ of 1% of the principal amount of the Series B Bonds; that the Underwriters and such dealers may allow a discount of ¼ of 1% of such principal amount on sales to other dealers; and that the public offering price and concessions and discounts to dealers may be changed by the Representative.

EXPERTS

The financial statements and schedules included in this Prospectus and elsewhere in the Registration Statement, to the extent and for the periods indicated in their reports, have been examined by Arthur Andersen & Co., independent public accountants, and are included herein in reliance upon the authority of said firm as experts in accounting and auditing in giving said reports.

LEGAL OPINIONS

Legal matters in connection with this offering will be passed upon for the Company by May, Bilodeau, Dondis & Landergan, Old South Building, 294 Washington Street, Boston, Massachusetts 02108, general counsel for the Company, and for the Underwriters by Palmer & Dodge, One Beacon Street, Boston, Massachusetts 02108. Members of the firm of May, Bilodeau, Dondis & Landergan participating in the matter own beneficially, directly or indirectly, 1,037 common shares of the Association. Thomas H. Bilodeau, a partner in the firm of May, Bilodeau, Dondis & Landergan, is a trustee of the Association and a director of NEGEA Service Corporation.

No dealer, salesman or any other person has been authorized to give any information or to make any representations other than those contained in this Prospectus, in connection with the offer contained in this Prospectus, and, if given or made, such information or representations must not be relied upon as having been authorized by the Company or the Underwriters. This Prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities in any jurisdiction to any person to whom it is unlawful to make such offer or solicitation in such jurisdiction. The delivery of this Prospectus at any time does not imply that the information herein is correct as of any time subsequent to its date.

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Canal Electric Company

$35,000,000

First and General Mortgage Bonds
Series B 8.85% Due 2006

PROSPECTUS

THE FIRST BOSTON CORPORATION

SEABROOK STATION

GENERAL and FINANCIAL INFORMATION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SEABROOK, NEW HAMPSHIRE

Volume 2

GENERAL AND FINANCIAL INFORMATION

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THE CONNECTICUT LIGHT AND POWER COMPANY

Units No. 1 and No. 2

Seabrook Nuclear Power Station

Seabrook, New Hampshire

Information furnished pursuant to Sec. 50.33 of Commission's Rules and Regulations with respect to the particular Applicant named above as part of Final Safety Analysis Report and Operating License Application for the above Units.

July 1981

I. ORGANIZATION AND CONTROL

(a) Name of Applicant

The Connecticut Light and Power Company (the Company or CL&P).

(b) Address of Applicant

Selden Street, Berlin, Connecticut 06037
P.O. Box 2010, Hartford, Connecticut 06101

(c) Description of Business of Applicant

CL&P is part of the Northeast Utilities system (the System) and is a wholly-owned subsidiary of Northeast Utilities[1]. The Company is a Connecticut corporation, organized in 1907, and is qualified as a foreign corporation in Massachusetts and New Hampshire. CL&P is the largest electric and gas utility in Connecticut. It is engaged principally in the production, purchase, transmission, distribution and sale of electicity and gas at retail for residential, commercial, industrial and municipal purposes within the State of Connecticut.

About 84% of CL&P's consolidated operating revenues for 1980 came from electric operations and 16% from gas operations. CL&P together with The Hartford Electric Light Company, Western Massachusetts Electric Company, Holyoke Water Power Company and Holyoke Power and Electric Company comprise the System's operating utility companies and are treated as a single participant in the New England Power Pool (NEPOOL) Agreement. CL&P's generating facilities together with those for the other System companies are operated as a single system through the New England Power Exchange, (NEPEX) the central dispatch agency of NEPOOL. The Agreement also provides for a determination of the generating capacity responsiblities of participants and their transmission rights and responsibilities.

During 1980, Northeast Utilities' energy requirements were met approximately 50% by nuclear units, 47% by fossil-fired units, and 3% by hydroelectric units.

CL&P has a 53% ownership interest in Millstone Unit Nos. 1 and 2 and the Northfield Mountain pumped storage facility, as tenant in common with HELCO and WMECO.

CL&P is a part owner, with other New England electric utilities, of the common stock of four regional nuclear generating companies. These companies are Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company, Vermont Yankee Nuclear Power Corporation and Yankee Atomic Electric Company, in which CL&P has 25%, 8%, 6% and 15% common stock interests, repectively.

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[1]Unless otherwise indicated, responses herein are for CL&P, rather than for the System as a whole.

The only major new generating facilities under construction in which CL&P has an interest are the Millstone Unit No. 3 nuclear generating unit in Waterford, Connecticut and Seabrook Unit Nos. 1 and 2 in Seabrook, New Hampshire.

For a more complete description of the business of CL&P, see pages 1-32 of 1980 Annual Report on Form 10-K (Exhibit A hereto).

(d) Corporate Organization

CL&P is a business corporation organized under the laws of Connecticut. As of December 31, 1980, CL&P had one domestic shareholder (Northeast Utilities) owning 8,931,014 common shares.

(e) Corporate Officers and Directors

The names and residence addresses of each of the members of CL&P's Board of Directors and of each of CL&P's Officers are listed below.

Directors

Name	Address
William B. Ellis (President and COO)	17 Colony Road, West Hartford, CT 06117
Walter F. Fee (Exec. VP)	43 Tee Lane, Wethersfield, CT 06109
E. James Ferland (Exec. VP and CFO)	Laurel Grove Drive, Higganum, CT 06441
Leon E. Maglathlin, Jr. (Senior VP)	173 Ardsley Road, Longmeadow, MA 01106
Herbert W. Sears (Senior VP)	192 Old Main Street, Rocky Hill, CT 06067
Lelan F. Sillin, Jr. (Chairman and CEO)	Route 156, RFD #2, Lyme, CT 06317
Peter M. Stern (VP)	Ash Swamp Road, Glastonbury, CT 06033
Donald C. Switzer (1) (Vice Chrm.)	7 Glen Road, Granby, CT 06035
Walter F. Torrance, Jr. (Sr. VP, Gen. Counsel & Asst. Secy.)	148 Tuttle Road, Woodbury, CT 06798
Anthony E. Wallace (2) (Exec. VP)	201 Andrews Street, Southington, CT 06489

(1) Retired effective 5/1/81.
(2) Retired effective 1/1/81.

OFFICERS

Title	Name	Address
Chairman & Chief Executive Officer	Lelan F. Sillin, Jr.	Route 156, RFD #2, Lyme, CT 06317
Vice Chairman	Donald C. Switzer (1)	7 Glen Road, Granby, CT 06035
President & Chief Operating Officer	William B. Ellis	17 Col[illegible]y Road, West Hartford, CT 06117
Executive Vice President	Walter F. Fee	43 Tee Lane, Wethersfield, CT 06109
Executive Vice President & Chief Financial Officer	E. James Ferland	Laurel Grove Drive, Higganum, CT 06441
Executive Vice President	Anthony E. Wallace (2)	201 Andrews Street, Southington, CT 06489
Senior Vice President	William G. Counsil	212 Natchaug Drive, Glastonbury, CT 06033
Senior Vice President	Leon E. Maglathlin, Jr.	173 Ardsley Road, Longmeadow, MA 01106
Senior Vice President	Herbert W. Sears	192 Old Main St., Rocky Hill, CT 06067
Senior Vice President, General Counsel & Assistant Secretary	Walter F. Torrance, Jr.	148 Tuttle Road, Woodbury, CT 06798
Vice President	Philip T. Ashton	39 Daffodil Lane, Meriden, CT 06450
Vice President	Warren F. Brecht	29 Stevens Place, Rocky Hill, CT 06067
Vice President	C. Thayer Browne (5)	85 Tracy Drive, Manchester, CT 06040
Vice President	Carroll A. Caffrey	Creamery Road, Durham, CT 06422
Vice President	John P. Cagnetta (5)	97 Butternut Circle, Wethersfield, CT 06109
Vice President	Raymond E. Donovan	10 Baldwin Street, Meriden, CT 06450
Vice President and General Manager - Gas	Bernard M. Fox (3)	246 High Tower Road, Southington, CT 06489
Vice President	Albert J. Hajek (5)	22 Hemlock Lane, East Hartford, CT 06118
Vice President	Warren A. Hunt (5)	16 Barn Hill Road, Bloomfield, CT 06002
Vice President	Francis L. Kinney	76 Pheasant Run, Newington, CT 06111
Vice President and General Manager - Gas	Jack R. McClendon (4)	4 Hickory Hill, Southington, CT 06489
Vice President and Treasurer	Leonard A. O'Connor	8 Centerwood Drive, Cromwell, CT 06416
Vice President	John F. Opeka (5)	10 Nottingham Drive, Old Lyme, CT 06371
Vice President	Walter T. Schultheis	91 Robert Road, Manchester, CT 06040
Vice President	Ralph O. Smith (5)	141 Braemar Drive, Cheshire, CT 06410
Vice President	Peter M. Stern	Ash Swamp Road, Glastonbury, CT 06033
Vice President	Richard P. Werner (5)	143 Robin Avenue, Glastonbury, CT 06033
Regional Vice President	Charles S. Beach	164 Hickory Hill La., Newington, CT 06111
Regional Vice President	W. Lindsey Booth	27 Randeckers Lane, Kensington, CT 06037
Regional Vice President	Thomas F. Brennan	201 Tunxis Road, West Hartford, CT 06107
Regional Vice President	Emil B. Gross	Old Pawson Road, Branford, CT 06405
Regional Vice President	Albert E. Magee	237 Dale Road, Wethersfield, CT 06109
Secretary	Robert W. Bishop	475 Simsbury Road, Bloomfield, CT 06002
Controller	George D. Uhl (5)	235 Minnechaug Dr., Glastonbury, CT 06033
Assistant Secretary	Cheryl W. Grisé (5)	66 Roberts Road, Marlborough, CT 06447
Assistant Secretary	Roy M. Seger	139 Andrews St., Southington, CT 06489
Assistant Secretary	Douglas R. Teece (6)	61 Paucatuck Rd., W. Springfield, MA 01089
Assistant Treasurer	Robert C. Aronson	62 Spring Lane, West Hartford, CT 06107
Assistant Treasurer	Michael K. Upper	70 Sunset Ridge Dr., Southington, CT 06489

(1) Retired effective 5/1/81.
(2) Retired effective 1/1/81.
(3) Elected effective 5/15/81.
(4) Retired effective 7/1/81.
(5) Elected effective 6/1/81.
(6) Elected effective 6/8/81.

All of the directors and principal officers of CL&P are citizens of the United States of America. CL&P is not owned, controlled or dominated by an alien, foreign corporation or foreign government.

II. FINANCIAL QUALIFICATIONS

Under the Seabrook Joint Ownership Agreement, CL&P is responsible for its Ownership Share of the operation and maintenance cost of the Units which will be 4.05985% of those costs, and a similar percentage of the utlimate cost of decommissioning the Units.

Based upon the estimates set forth above under Part IV of the General Information, CL&P's share of these costs should amount approximately to $6,090,000 and $6,090,000 for the first five years of operations of Unit 1 and 2, respectively; and approximately $1,705,000 to $3,491,000 for the decommissioning of both Units. In addition, CL&P's share of fuel expenses for both Units during the period 1983 through 1989 would be approximately $20,827,000.

As evidence of its financial qualifications to meet those costs, CL&P submits herewith:

(i) 1980 Annual Report to Stockholders included by reference in Form 10-K (Included in Exhibit A)

(ii) 1980 Annual Report on Form 10-K (Exhibit A)

(iii) 1981 First Quarter Report on Form 10-Q (Exhibit B)

(iv) Prospectus, dated September 16, 1980, relating to $65,000,000 of First Morgage Bonds, Series FF (Exhibit C)

(v) Rate order, dated October 9, 1980, (Exhibit D) Supplemental Decision dated October 17, 1980, (Exhibit D-1) and Errata dated October 22, 1980, (Exhibit D-2) and Errata dated October 24, 1980, (Exhibit D-3) of the State of Connecticut Department of Public Utility Control.

III. REGULATORY AGENCIES AND PUBLICATIONS

(a) Regulatory Agencies

The names and addresses of regulatory agencies which may have jurisdiction over the rates and services incident to the generation or distribution of energy by CL&P are as follows:

Department of Public Utility Control
State Office Building
165 Capitol Avenue
Hartford, Connecticut 06115

Federal Energy Regulatory Commission
Washington, D.C. 20426

(b) Publications

The following publications are used by CL&P for official notifications, and/or are otherwise appropriate for notices regarding these units:

The Ansonia Sentinel
241 Main Street
Ansonia, CT 06401

Bridgeport Post - Telegram
410 State Street
Bridgeport, CT 06602

Bristol Press
99 Main Street
Bristol, CT 06010

The Danbury News - Times
33 Main Street
Danbury, CT 06810

Greenwich Time
20 East Elm Street
Greenwich, CT 06830

The Hartford Courant
285 Broad Street
Hartford, CT 06115

The Meriden Record
214 Center Street
Meriden, CT 06450

Naugatuck Daily News
195 Water Street
Naugatuck, CT 06770

The New Britain Herald
One Herald Square
New Britain, CT 06050

The New Haven Register
367 Orange Street
New Haven, CT 06503

The New London Day
47 Eugene O'Neill Drive
New London, CT 06320

The Norwalk Hour
346 Main Avenue
Norwalk, CT 06851

Norwich Bulletin
66 Franklin Street
Norwich, CT 06360

Waterbury Republican - American
389 Meadow Street
P. O. Box 2090
Waterbury, CT 06720

The Willimantic Chronicle
P. O. Box 167
Chronicle Road
Willimantic, CT 06226

Winsted Evening Citizen
448 Main Street
Winsted, CT 06098

Exhibit A

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 December 31, 1980. Commission file number 0-404

THE CONNECTICUT LIGHT AND POWER COMPANY
(Exact name of registrant as specified in its charter)

CONNECTICUT	06-0303850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)
Selden Street, Berlin, Connecticut	06037
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (203) 666-6911

Securities registered pursuant to Section 12(b) of the Act: None

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

Cumulative Preferred Stock, par value $50.00 per share, issuable in series, of which the following series are now outstanding:

$2.00 Series of 1947	$3.24 Series G of 1968
$1.90 Series of 1947	$4.48 Series H of 1970
$2.20 Series of 1949	$4.48 Series I of 1970
$2.04 Series of 1949	$3.80 Series J of 1971
$2.06 Series E of 1954	$4.56 Series K of 1974
$2.09 Series F of 1955	$5.52 Series L of 1975

(Title of class)

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 X No ____

State the aggregate market value of the voting stock held by nonaffiliates of the registrant.

Not Applicable

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

Class	Outstanding at March 3, 1981
Common Stock, $10.00 par value	8,931,014 shares

Documents incorporated by reference:
Portions of the Annual Report to Stockholders for the year ended December 31, 1980 are incorporated by reference into Parts I and II.

THE CONNECTICUT LIGHT AND POWER COMPANY

PART I

Item 1. Business

THE COMPANY

The Connecticut Light and Power Company (the Company or CL&P) is part of the Northeast Utilities system (the System) and is a wholly-owned subsidiary of Northeast Utilities. The Company is a Connecticut corporation, organized in 1907, and is qualified as a foreign corporation in Massachusetts and New Hampshire. The Company is the largest electric and gas utility in Connecticut. It is engaged principally in the production, purchase, transmission, distribution and sale of electricity and the purchase, distribution and sale of gas at retail for residential, commercial, industrial and municipal purposes within the State of Connecticut.

The Company, The Hartford Electric Light Company (HELCO), Western Massachusetts Electric Company (WMECO), and Holyoke Water Power Company (HWP) are the principal operating subsidiaries of the System. Other subsidiaries of Northeast Utilities provide substantial support to the System companies. Northeast Utilities Service Company (the Service Company) supplies centralized accounting, administrative, data processing, engineering, financial, legal, operations, planning, purchasing and other services to the System companies. Northeast Nuclear Energy Company (NNECO) acts as agent for System companies in constructing and operating nuclear generating facilities and in financing nuclear fuel for such facilities. The Connecticut Gas Company (Conn Gas), a wholly-owned subsidiary of the Company, performs gas supply functions for CL&P and HELCO. The Rocky River Realty Company and The Quinnehtuk Company are both real estate companies.

The System is operated on an integrated basis, under which the Directors and the principal officers of each operating subsidiary are (with some exceptions) the same.

THE UTILITY ENVIRONMENT

Utilities encounter many financial, operational and regulatory challenges. They are subject to federal and state energy policies whose direction can be changeable and unpredictable. The cost of fossil fuels used in generation of electricity and of gas for retail distribution continues to increase, while oil and gas supplies are subject to national and international political considerations beyond utilities' control. Conversion of oil-fired units to coal is considered desirable by many,

but requires substantial capital expenditures and relaxation of environmental requirements in certain instances. New base load generating units of all kinds involve large financial commitments and require long planning and construction periods. Regulatory delays and stringent licensing and operating requirements for nuclear generating plants are encountered, as is public controversy over nuclear power and waste disposal. National economic troubles, heightened conservation awareness, and higher electricity prices all affect the use of electricity. Pipeline and storage capacity strain gas utilities in periods of high cold weather demand. The regulatory process often inhibits timely rate increases necessary to keep up with inflation. Rate increases are typically inadequate to meet actual costs and fail to provide the needed return on equity. Lower earnings jeopardize compliance with charter and indenture coverage tests which must be met if a utility is to issue senior securities. Interest rates continue to fluctuate but they have remained unusually high in recent years.

CL&P and the other System companies share these problems in varying degrees. Difficulties in obtaining sufficient rate levels, coupled with a reduction in the growth rate for electric energy, have caused CL&P, HELCO and WMECO to reduce and defer portions of previously planned construction programs. Financial restraints have recently caused them to take steps to reduce their ownership shares of the Millstone Unit No. 3 nuclear generating station, which is under construction in Waterford, Connecticut. (See "Operations--Joint Projects".)

Yet in some respects the System companies have been able to reduce the effects of some problems common to utilities, although the benefit has been primarily for customers rather than investors. The System's reliance on oil-fired electric generation is among the lowest in New England and the metropolitan New York region, primarily because of nuclear generating capacity that has been placed in service since 1961, when the Yankee Atomic plant began operations in Rowe, Massachusetts. In 1980, approximately 50% of the electricity provided to the System's customers was generated by nuclear units. Although this percentage is below the 53% contribution of nuclear units in 1979, nuclear generation in 1980 conserved some 20,300,000 barrels of oil at a net savings to customers of $310,800,000. Nuclear energy costs System companies less than half the cost of oil to generate a kilowatt-hour of electricity, helping to make the electric bills for System customers lower than for customers of many neighboring utilities. As described elsewhere in this report, the System companies and their investors, however, incur substantial expenditures and bear substantial economic and regulatory burdens in connection with the construction and operation of nuclear units. These burdens are not all fully compensated through rates.

CONSTRUCTION AND FINANCING PROGRAM

Construction

The Company has heavy financial commitments for its construction program through at least 1985. The largest part involves completing the construction of additional nuclear electric generating units in order to reduce further its reliance on oil-fired generation. Construction program expenditures (including Allowance for Funds Used During Construction (AFUDC) but excluding nuclear fuel) in the period 1981 through 1985 are estimated to be as follows:

	1981	1982	1983	1984	1985
	(Thousands of Dollars)				
Electric Plant					
Production	$150,871	$144,997	$137,432	$141,526	$115,753
Substations and Transmission Lines ..	9,522	8,778	7,177	10,700	19,118
Distribution Operations	22,314	22,748	23,734	26,185	27,937
General	4,747	2,810	2,790	3,111	2,976
Gas Plant	20,283	24,939	17,706	18,010	16,656
TOTAL	$207,737	$204,272	$188,839	$199,532	$182,440

The expenditures shown above do not include the amounts that would be required if certain of the Company's generating units were to be converted from oil-burning to coal-burning, or amounts which may be required to assist the various Yankee nuclear generating companies to finance their capital requirements. See "Conservation and Coal Conversion" and "Operations--Joint Projects". The construction programs for 1981 and 1982 include approximately $3,050,000 and $1,334,000, respectively, for environmental control facilities.

The only major new generating facilities under construction in which the Company has an interest are the Millstone Unit No. 3 nuclear generating unit in Waterford, Connecticut and Seabrook Unit Nos. 1 and 2 in Seabrook, New Hampshire. Millstone Unit No. 3 is scheduled for completion in 1986. Seabrook Unit Nos. 1 and 2 are scheduled for completion in 1983 and 1985, respectively, but 1980 construction delays are expected to delay the units' in-service dates. See "Operations--Joint Projects". The following table sets forth anticipated construction expenditures (including AFUDC but excluding nuclear fuel) for the Company's share of the Millstone and Seabrook units. This table and the foregoing table reflect an increase in the Company's 34.5% share of the estimated construction cost of Millstone Unit No. 3 from $713,118,000 to $895,700,000 based on a review completed in December, 1980. They also

reflect CL&P's sale of a 10 MW (0.4% +) interest in the Seabrook units to a Massachusetts utility on January 30, 1981. Neither table reflects increases in the cost of the Seabrook units that are expected to result from a review of Seabrook construction costs currently being undertaken by Public Service Company of New Hampshire (PSNH), the lead participant in the Seabrook project. Neither table reflects possible reduction of CL&P's ownership interest in Millstone Unit No. 3 or further reductions of CL&P's ownership interest in Seabrook. See "Operations--Joint Projects".

	Millstone #3	Seabrook #1 and #2
Total Net MW Capability	1,150 MW	2,300 MW
CL&P's Ownership	34.5%	4.05985%
CL&P's Share of Net MW Capability	396.2 MW	93.4 MW
Estimated Construction Cost per KW	$ 2,260	$ 1,176
Estimated Expenditures by CL&P		
	(Thousands of Dollars)	
Before 1981 (Actual)	$288,405	$47,675
1981	85,046	18,670
1982	112,148	17,369
1983	121,973	10,543
1984	122,338	13,370
1985	108,810	2,080
After 1985	56,980	-

The Company and other utilities have found that the cost of constructing major facilities frequently increases substantially over earlier projections because of inflation, increased licensing requirements, new environmental regulations, schedule deferrals and other causes. See "Operations--Joint Projects" and "Regulatory and Environmental Requirements and Proceedings--NRC Nuclear Plant Licensing" for information about problems relating to the Seabrook units that have resulted in material cost increases.

On December 31, 1980, Northeast Utilities announced its decision to cancel two 1,150 MW nuclear units planned for Montague, Massachusetts. Completion of the units could have made a significant contribution to the System's oil displacement goals for the 1980s and 1990s. Nevertheless, the System's development of a new conservation and load growth management program for that period (see "Conservation and Coal Conversion"), and the opportunity it affords the System to reduce its capital program, led to the decision. Reduction of the capital program is expected to lessen the exposure of Northeast Utilities shareholders to repeated common stock sales at less than book value, and to require fewer preferred stock and bond sales by CL&P and other System companies. CL&P had a 39.8% interest in the Montague project, representing an investment of approximately $15,389,000 (including AFUDC). It intends to apply to state and federal regulatory authorities to recover $13,735,000 of its

investment through rates. Management believes that recovery of these costs is consistent with established rate-making principles, but the action of regulators with respect to specific project cancellations cannot be predicted. The Company considers the Montague site viable for future coal or nuclear units.

The Company expects that it will be able to meet projected customer loads reliably until at least the mid-1990s, despite previous and proposed sales of interests in nuclear generating units, previous deferrals of in-service dates for Millstone Unit No. 3, previous and anticipated deferrals of the in-service dates of the Seabrook units, and the cancellation of the Montague units. However, continued use of fossil fuel-fired units that would otherwise have been replaced by nuclear power is likely to increase generation costs over the level that would have been incurred if the Company's nuclear generating capacity were not reduced.

Nuclear Fuel

The Company estimates that its expenditures for nuclear fuel (including AFUDC and nuclear fuel for the Seabrook units) will be $7,716,000 in 1981, $8,156,000 in 1982, $4,894,000 in 1983, $9,021,000 in 1984 and $24,842,000 in 1985.

Fuel for Millstone Unit Nos. 1 and 2 is financed by NNECO. The investment in nuclear fuel located in the Millstone Unit Nos. 1 and 2 reactors is financed by NNECO through capital contributions or advances from Northeast Utilities and the issuance of secured notes and bank borrowings. Up to $50,000,000 of investment in nuclear fuel in process for the Units may be financed by NNECO pursuant to a fuel supply trust agreement, under which the trust owns and finances the nuclear fuel before it is placed in the reactor. The trust obtains funds by the sale of commercial paper and/or bank loans. NNECO is obligated to purchase the nuclear fuel from the trust when specific events occur. CL&P, HELCO and WMECO presently contemplate entering into a fuel supply trust agreement to finance their share of the nuclear fuel costs for Millstone Unit No. 3. Nuclear fuel costs are expected to recovered through rates as the fuel is consumed in reactors.

Conservation and Coal Conversion

On January 21, 1981 Northeast Utilities released its long-term conservation program, the major goals of which are to reduce oil dependence in the System's service territory and to assist customers to take cost-effective conservation actions. Implementation of the program will require a number of regulatory approvals and actions, and is subject to the System's ability to finance the capital expenditures associated with the program. The customer conservation elements of the program are intended to make it possible for the System to maintain energy load growth at no more than 1.5% per year, by making customers aware of conservation's potential, informing them about preferred technical and

economic means of conservation, and providing them with services and financial incentives to implement their conservation decisions. The System's own oil reduction goal is to cut the use of oil in generation to 10% or less by 1987 and to maintain that percentage thereafter. Placing Millstone Unit No. 3 in service by 1986, as scheduled, while retaining a substantial part of the System's present ownership, converting the most suitable System oil-burning units to coal, and adding hydro-electric capacity and refuse-derived energy are the major actions proposed to meet the System's 1987 goal.

As part of the System's program to reduce oil dependence, the Company proposes to convert up to four of its oil-fired electric generating units to coal. The units, which provide an aggregate of 556 MW of capacity, are Norwalk Unit Nos. 1 and 2 and Devon Unit Nos. 7 and 8. Before the Company will be able to begin the conversion effort, it will need to obtain financing for the conversions, and receive governmental approvals and actions (including authorization for CL&P to burn coal with a higher sulfur content than is presently permitted). The cost to the System of converting these four units, which does not include the cost of flue gas desulfurization equipment, is estimated at $126,000,000.

The Company will not voluntarily convert any units, and it will continue to oppose federal actions described below, unless the investment can be justified in light of the Company's financial condition or unless other satisfactory financial arrangements are made. The Company also opposes the use of desulfurization equipment, for both cost and environmental reasons. Conversion of any of the Company's units without desulfurization equipment would require changes in current state emission standards. Because of the need to improve the Company's financial condition and to resolve present regulatory and environmental uncertainties before the Company can convert any of the four units, the construction program expenditures given in the table under "Construction" above do not include any funds for coal conversion.

The System is currently planning voluntarily to convert HWP's Mt. Tom Station if CL&P, HELCO, WMECO and HWP receive necessary approvals to finance the estimated $35 million cost of conversion (of which approximately $22 million would be borne by the System and the balance will be borne by another utility system which shares the output of Mt. Tom Station) through the use of the oil conservation adjustment mechanism described in "Rates". Coal burning is expected to begin about one year after necessary rate and environmental approvals are received. The schedule for voluntary conversion of the Company's units would permit them to begin burning coal in 1985 and 1986, subject to the conclusion of satisfactory financing arrangements and receipt of necessary regulatory approvals.

The Company believes that its efforts to convert its units to coal on a voluntary basis will enable it to place coal-fired units in service on a sound environmental basis, earlier and at lower cost

than if it were required to convert certain of its units (including some but not all of the units covered by the System's voluntary plan) under federal mandate. Prohibition orders for two of the Company's units were issued under the Energy Supply and Environmental Coordination Act of 1974, but have been rescinded. The provisions of the Power Plant and Industrial Fuel Use Act of 1978 could require the conversion of up to five of the Company's units, with an aggregate capacity of approximately 638 MW. If all five units were required to convert to coal and were required to utilize flue gas desulfurization equipment, the estimated conversion cost would be approximately $343,000,000. Connecticut does not have an approved site for disposal of limestone sludge and ash, by-products of the flue gas desulfurization process.

Financing

In addition to financing the construction program, nuclear fuel expenditures, and any coal conversion of oil-fired units, as described above, the Company is obligated to expend $167,655,000 in 1981 through 1985 to meet long-term debt maturities and long term debt and preferred stock sinking fund requirements. In 1982 alone, sinking fund and debt maturity requirements are $123,531,000. In 1981 these requirements are $3,531,000.

In 1981 construction program expenditures, nuclear fuel expenditures and sinking fund and debt maturity requirements are expected to amount to $218,984,000 in the aggregate. Expenditures in 1981 for coal conversion under the Company's voluntary program are nominal. In 1982, the sum of construction program expenditures, nuclear fuel expenditures and sinking fund and debt maturity requirements is expected to be $335,95[illegible],000. Coal conversion costs would be an additional $23,500,000 if the voluntary program is implemented. The Company proposes to finance these expenditures through a combination of internally generated and external funds. The amount of internally generated funds that will be available cannot be known at this time because of such uncertainties as the results of rate cases and the offer to sell a part of the System's interest in Millstone Unit No. 3. The amount, nature and sources of external funds to be sought have not yet been definitively determined. External funds are expected to be required to provide at least half of the 1981 financing requirements of the Company.

The Company's ability to meet the proposed level of construction, nuclear fuel expenditures, coal conversion expenditures and refinancings of senior securities is primarily dependent on its ability to obtain timely and adequate rate relief and on conditions in the capital markets. Inadequate rate relief and instability in the capital markets have adversely affected the construction program in 1980 and earlier years. If adequate future rate relief and satisfactory financing terms cannot be obtained, the Company will be forced to make further deferrals or abandonments of proposed projects and further reductions of its ownership interests in generating units.

The Company typically finances current construction expenditures and other requirements in excess of internally generated funds through short-term borrowings, selling additional first mortgage bonds and preferred stock, leasing equipment, and the receipt of capital contributions and advances from Northeast Utilities. The Company received a capital contribution of $40,000,000 from Northeast Utilities during 1980, and it anticipates receiving capital contributions aggregating $30,000,000 during 1981.

The amounts of short-term borrowings which may be incurred by CL&P are subject to periodic approval by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935. Short-term or other unsecured borrowings are also restricted by the preferred stock provisions of its charter. The SEC limits, the preferred stock limitations, and the amounts of outstanding short-term borrowings, are set forth below as of December 31, 1980:

SEC Authorization	Limit under Preferred Stock Provisions	Commercial Paper	Short-Term Bank Loans**	Total Short-Term Debt Outstanding
$185,000,000*	$300,898,000	$85,785,000	$62,500,000***	$148,285,000***

*CL&P's SEC limit was increased to $210,000,000 on February 3, 1981.

**See note 6 to the financial statements for information about credit lines available to the Company.

***Includes borrowings of $27,500,000 under the Revolving Credit/Term Loan Agreement described below.

The System companies experienced an unexpected, rapid increase in their short-term borrowings in early 1981, primarily to finance increased oil purchases and expenditures for repairs at Millstone Unit No. 1. These were required by the need to extend a refueling outage at that unit so that plant repairs could be effected. The increase in short-term borrowings led CL&P and HELCO to obtain approval for additional temporary short-term borrowings in excess of their current SEC authorizations. Short-term borrowings were brought below the authorized level at the completion of ten-year term loan borrowings in early March 1981. CL&P's term loan is $100,000,000 and HELCO's term loan is $50,000,000. The loans are secured by second mortgages on the borrowers' interests in Millstone Unit No. 1, and mature in four equal annual installments of principal beginning April 5, 1987.

In addition to their customary short-term borrowings from banks and from the sale of commercial paper, CL&P, HELCO and WMECO

entered into a Revolving Credit/Term Loan Agreement with a group of banks on August 25, 1980. The aggregate credit limit for all three companies under the Agreement is $140,000,000, with a maximum borrowing limit for CL&P of $80,000,000. The revolving period expires June 30, 1983. The Company has the option on or before June 30, 1983 of converting any borrowings permitted under the Agreement to a term loan maturing June 30, 1987 and amortizing in eight equal semi-annual installments commencing December 31, 1983.

The indenture securing the outstanding mortgage bonds of CL&P provides that additional bonds may not be issued, except for certain refunding purposes, unless earnings (as defined in the indenture) are at least twice the pro forma annual interest charges on outstanding bonds and the bonds to be issued. The Company's preferred stock provisions prohibit the issuance of additional preferred stock unless earnings (as defined) are at least one and one-half times the pro forma annual interest charges on indebtedness and the annual dividend requirements on preferred stock that will be outstanding after the additional stock is issued.

On the basis of the indenture and preferred stock formulas, the coverages for the years ended December 31, 1978, 1979 and 1980 were, based on the amounts outstanding as of the end of such periods, as follows:

Year Ended	Bond Coverage	Preferred Stock Coverage
December 31, 1978	2.25	1.60
December 31, 1979	2.19	1.45
December 31, 1980	2.05	1.27

In September, 1980 CL&P issued and sold publicly $65,000,000 aggregate principal amount of its 14-3/8% First Mortgage Bonds.

The sale of any additional securities by the Company will continue to depend on the adequacy of future earnings, on generally prevailing interest rates and other conditions in securities markets, and on the market appraisal of the Company's securities.

OPERATIONS

Electric

System operating companies own and operate a fully-integrated electric utility business. Generation and transmission facilities are planned and operated as part of a regional New England bulk power system. See "Joint Projects". System transmission lines

form part of New England transmission system linking System generating plants with one another and with the facilities of other utilities in the northeastern United States and Canada.

Since 1970 the System companies have pooled their electric production costs and the costs of their principal transmission facilities. This arrangement makes unit bulk power costs of the System companies substantially uniform.

About 84% of the Company's consolidated operating revenues for 1980 came from electric operations. Electric revenues for both 1980 and 1979 were derived 43% from residential customers, 25% from commercial customers, 21% from industrial customers, 8% from wholesale customers and the balance from others. The Company furnishes firm wholesale electric service to three municipal electric systems and one investor-owned electric system.

As of October 1, 1980 the Connecticut Municipal Electric Energy Cooperative (CMEEC) assumed responsibility for serving three Connecticut municipal electric systems which had previously been firm wholesale customers of CL&P. CL&P and other System companies have agreed to sell CMEEC transmission service and unit-contract entitlements in a number of the System's electric generating units, including all nuclear units in which System companies have entitlements.

Through March 3, 1981 the all-time maximum demand on the System was 4,126,000 kilowatts, which occurred on January 12, 1981 at which time the generating capacity of the System's generating plants (including the System companies' entitlements in regional nuclear generating companies) was 6,373,400 kilowatts. At the time of the peak, the System was selling 338,900 kilowatts of capacity from its plants to other utilities, and it was purchasing 8,000 kilowatts from other utilities in order to take advantage of lower fuel costs of the selling utility. The System's capacity which is in excess of its needs, including reserve requirements, is offered for sale to other utilities. The System expects to have capacity available from its existing units for sales to other utilities until at least 1989.

The System's and CL&P's kilowatthour sales for 1980 were both 0.4% above the level for 1979. During 1980, the System's energy requirements were met 50% by nuclear units, 47% by fossil fired units, and 3% by hydroelectric units. During 1979, the System's energy requirements were met 53% by nuclear units, 43% by fossil fired units, and 4% by hydroelectric units. The System's goal is to promote conservation measures that will help contain the growth in the demand for electricity to 1.5% annually over the long term. See "Construction and Financing Program--Conservation and Coal Conversion" for information about the System's conservation and load growth plans.

Gas

CL&P and HELCO furnish retail gas service in eleven separate service areas, not interconnected, that cover approximately 1,535 square miles in [illegible] cities and towns in Connecticut with an estimated population of 1,2[illegible],5[illegible]0. Eight of the eleven service territories are CL&P's. About 16% of the Company's consolidated operating revenues for 1980 came from gas operations. Gas revenues in 1980 were derived 42% from residential customers, 20% from commercial customers, 35% from industrial customers and the balance from others. In 1979 gas revenues were derived 45% from residential customers, 18% from commercial customers, 35% from industrial customers, and the balance from others.

Since January 1, 1979 CL&P and HELCO have obtained their gas supply at uniform costs through CL&P's subsidiary, Conn Gas. Pipeline gas provided 95.3% of the companies' 1980 requirements. Liquified natural gas (LNG) provided 4.2% and propane provided the remainder. System gas requirements for 1981 are expected to be met approximately 97.1% by pipeline gas, 2.4% by LNG and the balance by propane. Pipeline gas is purchased under long-term contracts with Algonquin Gas Transmission Company (approximately 58%) and Tennessee Gas Pipeline Company (approximately 42%) at rates subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). During a number of winters since 1970, pipeline gas suppliers, with the approval of the FERC, have reduced below contract quantities the amount of pipeline gas made available to distribution companies, including CL&P and HELCO. The amounts supplied by Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company have not been significantly curtailed during the 1980-1981 heating season and are not expected to be significantly curtailed during the 1981-1982 heating season. Unusually cold weather in late December, 1980, and in January, 1981, strained the Company's gas supplies but did not result in any service interruptions.

Suppliers of pipeline gas have periodically obtained rate increases for their pipeline gas deliveries and have additional requests for rate increases pending before the FERC. Increases in purchased gas costs are by far the most significant factors in increased operating costs for gas service. Since 1973 CL&P has had an adjustment clause in its retail gas rate schedules under which billings to customers reflect changed gas costs.

Conn Gas, on behalf of CL&P and HELCO, has made arrangements to obtain quantities of LNG and propane to supplement pipeline gas supplies, and to provide additional storage for LNG. However, since the supply of LNG is dependent on foreign sources, future availability is uncertain. Conn Gas has also contracted for underground storage service for pipeline gas to be available in 1982, which will enhance the System's ability to utilize available natural gas. The Company anticipates that gas supplies will be adequate through at least the 1984-85 heating season.

Conn Gas, along with thirteen other gas companies in New England, New York, and New Jersey, has made arrangements to receive a ten-year supply of natural gas from TransCanada Pipelines Limited, a Canadian corporation. To facilitate their dealings with TransCanada, the participants have organized Boundary Gas, Inc., to purchase gas from TransCanada and to resell gas to the participants. In October, 1980 Conn Gas purchased a 5.11% stock ownership interest in Boundary Gas, which entitles and obligates it to purchase 5.11% of the natural gas that Boundary Gas is expected to purchase from TransCanada. Boundary Gas' total purchases for all participants are expected to be 185,000,000 cubic feet per day. It is estimated that gas purchased through Boundary Gas will represent approximately 8% of CL&P's and HELCO's gas supplies during the first full year of purchases. This Canadian gas is expected to be available in 1982.

Algonquin Gas Transmission Company and Transcontinental Gas Pipe Line Corporation, which supply Conn Gas and other utilities in the northeastern states, signed agreements in 1980 with Pan-Alberta Gas Ltd. for the purchase of up to 300,000,000 cubic feet of Canadian natural gas per day. The gas would be transported by two proposed pipelines, the Trans-Quebec Maritime Pipeline and the New England States Pipeline. The lines are scheduled for completion in 1983 and 1984, respectively, and are subject to various Federal, Canadian and state regulatory approvals. Conn Gas expects that approximately 11% of the gas would be made available to it pursuant to existing agreements with Algonquin Gas Transmission Company.

Each of these Canadian gas purchase arrangements requires approval of Canada's National Energy Board, which has questioned the extent to which Canada should export natural gas to the United States. Approval is therefore not assured.

A 1974 agreement among CL&P, HELCO and Connecticut Natural Gas Corporation (CNG) for the sale of CL&P's and HELCO's gas properties to CNG terminated in 1979. Since then CL&P and HELCO have undertaken, and are continuing, studies to determine an appropriate course of action with respect to their gas properties. The position of the SEC continues to be that companies subject to the Public Utility Holding Company Act of 1935 may not retain both gas and electric properties.

Segments of Business

Information about the Company's business segments is given in note 12 to financial statements, which are included in Exhibit 13 to this report.

Employees

As of December 31, 1980, the Company had a total of 3,822 regular employees on its payroll. It has union agreements covering a total of 2,017 employees.

CL&P and HELCO have consolidated their operations by transferring all HELCO personnel (other than production personnel) to CL&P. CL&P now provides local service to customers of both companies and bills HELCO for its share on a recovery-of-cost basis. CL&P and HELCO are continuing to investigate the feasibility of a corporate merger, in which CL&P would be the surviving corporation.

Joint Projects

NEPOOL

System operating companies and most other New England utilities with electric generating facilities are parties to the New England Power Pool (NEPOOL) Agreement. Under the Agreement the generating facilities of all participants are operated as a single system through the New England Power Exchange, a central dispatch facility. The Agreement also provides for a determination of the generating capacity responsibilities of participants and their transmission rights and responsibilities. Pool dispatch results in substantial purchases and sales of electric energy by pool participants, including the Company, at prices determined in accordance with the NEPOOL Agreement.

Jointly Owned Nuclear Units

CL&P, HELCO and WMECO own Millstone Unit Nos. 1 and 2 and the Northfield Mountain pumped storage facility as tenants in common. Their ownership interests are 53%, 28% and 19%, respectively.

CL&P has agreements with other New England utilities (including HELCO and WMECO) covering their joint ownership of the future nuclear units referred to under "Construction and Financing Program." The arrangements provide for pro rata sharing of construction and operating costs and the electrical output of each unit by the owners, as well as pro rata sharing of associated transmission costs.

CL&P is a part owner with other New England electric utilities (including HELCO and WMECO) of the common stock of four regional nuclear generating companies. These companies are Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company, Vermont Yankee Nuclear Power Corporation, and Yankee Atomic Electric Company (the Yankee companies), in which the Company has 25%, 8%, 6% and 15% common stock interests, respectively.

The Rowe, Massachusetts, nuclear generating unit of Yankee Atomic Electric Company returned to service in November, 1980 at 86% of its former rating after a long outage resulting from severe steam turbine damage. The damage was not nuclear-related.

CL&P is obligated, within specified limits, to provide its percentage of such additional equity capital as may be necessary for the Yankee companies. The owners of Vermont Yankee Nuclear Power Corporation have agreed in principle to guarantee their pro rata shares of a $40,000,000 nuclear fuel financing; completion of the transaction is subject to the receipt of regulatory approvals and the execution of definitive agreements. The owners of Connecticut Yankee Atomic Power Company agreed in 1980 to

an interim financing arrangement under which each would purchase its pro rata share of up to $40,000,000 of Connecticut Yankee's subordinated notes to meet nuclear fuel financing obligations, construction program expenditures and other needs. The Company's share would be $10,000,000. Through March 3, 1981, $21,000,000 of such notes were issued, of which the Company's share was $5,250,000. The Company believes that the Yankee companies will require additional external financing in the next several years to finance construction expenditures and nuclear fuel or for other purposes. Although the ways in which each Yankee company will attempt to finance these expenditures have not been finally determined, the Company expects that it may be asked to provide additional equity capital and/or other types of direct or indirect financial support for one or more Yankee companies.

Proposed Millstone Unit No. 3 Sales

In January 1981, CL&P, HELCO and WMECO made offers to sell to other utilities a minimum of an 8.7% interest (approximately 100 MW) in Millstone Unit No. 3 and invited expressions of interest in amounts in excess of 100 MW. The companies decided to make this offer in light of their financial condition and to lessen the need for Northeast Utilities to sell additional common stock below book value and for CL&P, HELCO and WMECO to sell additional preferred stock and bonds to finance the remaining construction costs for the unit.

Determinations of whether more than 100 MW will be sold, and how the total amount to be sold will be allocated among the companies, are to be made following receipt of responses to the offer and will be based on the then-financial outlook of each of the companies and the amount of interest expressed by the other utilities. Responses to the offer are due on or before July 6, 1981. Subject to the receipt of necessary regulatory approvals, sales could begin as early as September, 1981, but are unlikely to occur before the end of 1981. The purchase price is a pro rata share of the selling companies' book value for their investment in the unit, including AFUDC and nuclear fuel. Utilities responding to the offer have been asked to indicate whether they wish to pay for their ownership interests in a single payment or to pay in quarterly, interest-bearing installments over several years until 1986, when the unit is scheduled to be placed in service. The companies have reserved the right to determine how much capacity to sell on each basis. Assuming a cash sale at December 31, 1981, the purchase price for a 100 MW ownership interest would be approximately $98,200,000. The extent of acceptance of the offer cannot be known until the expiration date for the offer. Another co-owner of the unit has an offer pending to sell part of its interest in the unit. Experience with offers by System companies and other utilities indicates that needed regulatory approvals may be time-consuming or, in some instances, not forthcoming.

If the Company is unsuccessful in its effort to reduce its interest in Millstone Unit No. 3, and if the Company's financial condition

does not improve substantially through rate increases or otherwise, the Company would be forced to take alternative action, including selling other assets or substantially reducing construction and operating expenditures. As of December 31, 1980 the Company had invested approximately $303,700,000 in the unit (including AFUDC and nuclear fuel expenditures). At that date the engineering on the project was approximately 74% complete and construction approximately 33% complete. The reactor containment structure and the turbine building structure are essentially complete. The reactor vessel and major portions of the turbine generator are in place and a substantial number of other components are on site.

Seabrook

PSNH has responsibility for constructing and scheduling the two Seabrook units. PSNH has been experiencing serious difficulties in financing its construction program. To alleviate its financial difficulties, PSNH has attempted to reduce its ownership share in the units. Other utilities have agreed to acquire ownership shares from PSNH representing approximately 14.77% interests in the units. PSNH will have a 35.23% + interest in the units if all such reductions are completed. PSNH has advised the Company that as of March 3, 1981 each acquiring utility had obtained all regulatory approvals necessary to acquire its interest, and that reduction of PSNH's interest had begun with respect to each such utility, except in the case of one Massachusetts utility (0.33445%) for which local municipal approvals had not been received, and a New Hampshire electric cooperative (2.17391%) for which NHPUC approval had not been received. Other owners of Seabrook have indicated a desire to reduce their ownership shares. Offers to sell by PSNH and other owners are expected to affect adversely CL&P's ability to reduce its ownership (approximately 4%) further.

On January 30, 1981, CL&P sold to a Massachusetts utility a 10 MW interest (0.4% +) in the Seabrook plant. The sales price was approximately $5,636,000. On October 30, 1980, the Massachusetts Department of Public Utilities (DPU) denied another Massachusetts utility's petition to purchase an additional 23.8 MW interest (1.0% +) from CL&P, on the ground that the prospective purchaser had failed to prove its financial capacity to fund the purchase. CL&P is not actively seeking offers to purchase its remaining interest, although it is still willing to reduce or dispose of its interest on terms satisfactory to it. No other utilities have recently expressed an interest in purchasing CL&P's interest.

In 1980, construction of one or both Seabrook units was delayed for extended periods on several occasions because of PSNH's decision in March, 1980 to reduce substantially the overall level of construction, because of an order (later amended) of the New Hampshire Public Utility Commission (NHPUC) that required PSNH to postpone for three years construction of Seabrook Unit No. 2 other than work common to both units, and because of a ten-week ironworkers' strike. These

reductions and delays have adversely affected the scheduled in-service dates and construction cost estimates. PSNH is currently under an order of the NHPUC preventing it from expending further funds on the construction of Seabrook Unit No. 2 until receipt of necessary regulatory approvals for the acquisition by certain Massachusetts utilities of a portion of PSNH's interest in the Seabrook units and until reduction of PSNH's interest begins. As of March 3, 1981, these conditions had not been entirely satisfied, so full construction activity at both units had not resumed.

If the remaining regulatory approvals required to permit PSNH to reduce its ownership interest are not received (and some approvals have been denied on previous occasions), or if PSNH's financing program cannot be carried out, the in-service dates for one or both of the Seabrook units might be deferred further, or construction of the units might be further delayed or suspended until PSNH's financial problems are resolved.

Fuel for Generating Stations

Oil

In 1980 approximately 18,600,000 barrels of oil were consumed in the generation of electricity provided to the System's customers. This amount includes more than 2,000,000 barrels of oil estimated to have been used to generate power purchased in 1980 from other utilities. Oil-fired generation produced approximately 47% of the electricity provided to the System's customers in 1980. The System's storage capacity is approximately 3,000,000 barrels of oil and the inventory is generally sufficient for approximately 45-days of operations.

While the System is currently able to obtain its full oil requirements, instability in world oil supplies makes the adequacy of future supplies less certain. More than 60% of the oil for the System's generating units is purchased under a contract with Amerada Hess Corporation which expires in August 1982 but may be renewed from year to year by mutual agreement. The contract is for a specific quantity of oil but the price may increase or decrease since it is based on a specified discount from the posted price. The balance of System oil requirements is purchased under contracts for one year or less. The cost per barrel has increased substantially from approximately $14.50 per barrel in December, 1978 to approximately $30 per barrel at the end of 1980 and approximately $39 at March 3, 1981. The cost is expected to rise even higher in the current year.

Coal

The Company does not presently operate any coal-burning electric generating units. It has studied the cost, availability and sources of

coal supplies and transportation services, and has conducted preliminary negotiations with potential suppliers, in preparation for the possible conversion of one or more units from oil to coal. See "Construction and Financing Program--Conservation and Coal Conversion". The Company believes that, if any or all of the units are converted, the capacity of available surface transportation, marine transportation and coal production will be adequate for its requirements.

Nuclear Fuel

To the extent indicated below, there are outstanding contracts for uranium concentrates and conversion, enrichment and fabrication for the System's existing and planned units, and the other units in which the Company is participating, which cover the units' requirements through the following years:

	Uranium Concentrates	Conversion to Hexafluoride	Enrichment	Fabrication
Connecticut Yankee	1986	1985	1995	1986
Maine Yankee (1)	1986	1982	2000	1984
Vermont Yankee (1)	1982	1982	2001	1983
Yankee Atomic (1)	1986	1982	1999	1983
Seabrook Unit No. 1 (1)	1985	1987	2009	1987
Seabrook Unit No. 2 (1)	1985	1987	2011	1987
Millstone Unit No. 1	1987	1989	2001	1992
Millstone Unit No. 2	1986	1989	2001	1986
Millstone Unit No. 3	1990	1989	2014	1993

(1) The information in the table for these units has been furnished to the Company by the utility company having responsibility for operation of the unit.

The Company expects that uranium concentrates and related services for periods not covered by existing contracts will be available, although their availability will require that suppliers develop additional capacity.

Nuclear Waste Disposal and Decommissioning Costs

Costs associated with nuclear plants include amounts for the disposition of nuclear wastes, including spent fuel, and for the ultimate decommissioning of the plants. The Company reflects in its nuclear fuel expense the DOE's estimated cost of spent fuel disposal. This provision for spent fuel disposal has been accepted by the Connecticut Department of Public Utility Control (DPUC) in rate case decisions and is reflected in the wholesale fuel adjustment charges approved by the FERC. Such provisions, which reflect increases over previous levels, also include amortization, over a ten-year period, of the estimated disposal cost of accumulated spent nuclear fuel.

Although in planning their nuclear generating plants the System companies had expected that spent fuel would be reprocessed in commercial facilities, federal policy under the Carter administration had favored an indefinite postponement of commercial reprocessing. Operating nuclear generating plants would therefore need to retain spent fuel on-site longer than had been anticipated. Each of the operating nuclear plants listed under "Operations - Fuel for Generating Stations" is expected to have adequate storage capacity on site until at least the mid-1980's. The storage facilities for Connecticut Yankee and the Millstone Units, including facilities currently under construction at Millstone Unit No. 3, are expected to be adequate until at least the mid-1990's, by which time government storage and waste repository facilities are expected to be available to accept spent fuel. If government storage or waste repository facilities are not available, the Company may incur substantial additional costs in developing alternate storage arrangements.

Although the Carter administration had announced specific proposals for the disposal of nuclear wastes, no definite action was taken and the Reagan administration has not yet taken any formal actions. The Nuclear Regulatory Commission (NRC), along with other federal agencies, has been in the process of developing regulations and guidelines in this area. There may be additional costs (above those presently accepted by regulatory authorities) associated with the disposal of nuclear wastes, including spent fuel, from each of the nuclear plants in which the Company has an ownership interest.

The Company estimates decommissioning costs for its interest in nuclear units on the basis of complete dismantlement at retirement. The estimated decommissioning costs on this basis for Millstone Unit Nos. 1 and 2 and Connecticut Yankee are in the range of $65-80 million per unit, in 1980 dollars. If alternative or additional decommissioning arrangements are required, these cost estimates may increase. Only the portion of the presently estimated total decommissioning costs which has been accepted by regulatory agencies is reflected in CL&P's depreciation expense. See note 1 to financial statements.

RATES

General

CL&P's retail electric and gas rate schedules are subject to the jurisdiction of the DPUC. Its wholesale electric rates are subject to the jurisdiction of the FERC.

Retail Rates

Connecticut law affords the DPUC 150 days to act upon a proposed rate increase. If the DPUC does not act within that period,

the proposed rates may be put into effect subject to refund. Interim rate increases, subject to refund, may be approved by the DPUC after a public hearing if they are found to be necessary to prevent substantial and material deterioration of the financial condition, or the adequacy and reliability of service, of a utility. Under Connecticut law, the DPUC is required to conduct a complete review and investigation of, and to hold a public hearing on, the financial and operating results of each electric and gas utility at least once every two years to determine whether an increase or decrease in the level of the utility's rates is required.

In October 1980, the DPUC granted CL&P an annual retail rate increase of approximately $81,600,000. CL&P's electric rates increased by an average of 13.1% and its gas rates by an average of 8.2%. CL&P had requested an increase of $111,400,000.

In its decision, the DPUC authorized a 14.5% return on common equity and approved accounting changes permitting the Company to accrue AFUDC on a net-of-income tax basis and to normalize certain tax timing differences previously treated on a flow-through basis. See note 1 to financial statements. The approved accounting changes represented approximately $26,200,000 of the total increase. The decision also recognized certain adjustments to historical test year data to reflect some of the conditions anticipated by the Company during the first year the amended rate schedules will be in effect, including an allowance for inflation of operation and maintenance expenses, increased rate bases and changed capitalizations. The DPUC also ordered no increase in the existing residential customer charge, flat residential rates and time-of-day rates with a 3¢ per kWh on-peak/off-peak differential.

The DPUC further ordered the Company to file timetables and plans for implementing a conservation program in accordance with guidelines set forth in the order. The System's conservation and load growth management plan--outlined under "Construction and Financing Program--Conservation and Coal Conversion"--was developed in part to respond to this requirement.

The Connecticut Division of Consumer Counsel has appealed from the DPUC decision in the 1980 rate case, alleging error on the part of the DPUC solely with respect to the approval of tax normalization and net-of-income tax AFUDC. The Company has appealed the decision solely with respect to the allowed return on common equity.

Following the completion of the 1980 rate case, the DPUC ordered hearings on electric heating customers' complaints about the DPUC-ordered flattening of residential rates. Hearings in this proceeding began in February, 1981. It is not expected that this proceeding will result in significant changes in CL&P's total revenues, although it may result in reallocation of revenues among classes of residential customers.

Since August 1, 1979, CL&P's retail rate schedules have included a generation utilization adjustment clause. Monthly, this clause levels the effect on fuel costs caused by variations from a 70% generation capacity factor for the nuclear units in which CL&P has entitlements. At the end of the twelve-month period ending July 31 of each year, any deferred balance resulting from the actual nuclear generation capacity factor for that period being below or above 70% will be either collected from or refunded to customers over the subsequent twelve-month period. However, the clause does not permit collection from customers to the extent that the nuclear generation capacity factor is less than 55% in the twelve-month period. For the period August 1, 1979 to July 31, 1980, the nuclear generation capacity factor was 71.2% resulting in a refund to customers of $2,354,000 over the succeeding twelve months.

For the five months ended December 31, 1980, the factor was 53.6%. Nuclear performance in the period has been below previous operating experience because certain nuclear units in which the Company has interests have been out of operation longer than had been anticipated for refueling, modifications and repairs.

The Company expectes to file an application with the DPUC for additional rate relief by mid-1981.

Fuel Adjustment Clauses

The Company has fuel adjustment clauses applicable to its retail and wholesale electric rates, and a purchased gas adjustment clause applicable to its retail gas rates.

Public proceedings are required by the DPUC each month on the charges proposed for the following month under retail fuel adjustment clauses and purchased gas adjustment clauses. Monthly fuel and gas adjustment charges are also subject to retroactive review and appropriate adjustment by the DPUC each quarter at full public hearings. The clauses only allow recovery of changes in prices of fossil fuel. Any other changes affecting energy costs are not covered by the clauses.

Oil Conservation Adjustment

In 1979, discussions among Massachusetts officials and Northeast Utilities on the subject of converting oil-burning plants in that state to coal led to the development of the concept of an oil conservation adjustment (OCA) to assist in the financing of conversion costs. The OCA is a mechanism by which two-thirds of the fuel cost savings per kWh resulting from the conversion would be collected through rates and retained by the utility company until the full cost of conversion is paid. CL&P and other System companies are in the process of obtaining the regulatory approvals necessary to incorporate the OCA in retail and wholesale rates in order for HWP's Mt. Tom station to be converted to coal. See "Construction and Financing Program--Conservation and Coal Conversion" for information about the conversion costs for this unit.

Wholesale Rates

On August 29, 1980, Connecticut Yankee Atomic Power Company, of which the Company has a 25% stock ownership, submitted for filing with the FERC contracts amending the contracts under which the sponsoring utilities, including CL&P, HELCO and WMECO, purchase the output of the Connecticut Yankee generating unit. The amendments provide for a variable, rather than a fixed, rate of return on net unit investment which will fluctuate with changes in long-term interest costs and preferred stock dividends paid by Connecticut Yankee. The amended rates would yield an annual increase of approximately $12,839,000 above currently allowed rates, and approximately $6,960,000 above currently collected revenues. On October 28, 1980 the FERC accepted for filing and suspended for five months the rate changes reflected in the proposed amendment. The rate changes will become effective April 1, 1981, subject to refund. Connecticut Yankee expects to file a settlement proposal with the FERC under which the proposed increase of $12,839,000 per year would be reduced by $6,492,000 annually.

See "Legal Proceedings" for a description of litigation and administrative proceedings involving retail and wholesale rate cases for years before 1980.

REGULATORY AND ENVIRONMENTAL REQUIREMENTS AND PROCEEDINGS

Public Utility Regulation

Northeast Utilities is registered with the SEC as a holding company under the Public Utility Holding Company Act of 1935. Under that Act, the SEC has jurisdiction over Northeast Utilities, the Company and other System companies with respect to, among other things, securities issues, sales and acquisitions of securities and utility assets, intercompany loans, services performed by and for associated companies, accounts and records, and dividends.

CL&P is subject to regulation by the DPUC, which has jurisdiction, among other things, over rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, securities issues, standards of service, management efficiency, and construction and operation of generation, transmission and distribution facilities.

The Company is subject to the general supervision of the DPU with respect to all dealings with WMECO and HWP, and to the jurisdiction of the NHPUC for limited purposes in connection with its ownership interest in the Seabrook units.

The Company is a public utility under Part II of the Federal Power Act and is subject to regulation by the FERC with respect to, among other things, interconnection and coordination of facilities, wholesale rates and accounting procedures.

The Company incurs substantial capital expenditures and operating expenses to comply with environmental, energy, licensing and other regulatory requirements, including those described in the following subsections, and it expects to incur additional costs to meet further developments in these and other areas of regulation. Because of the continually changing nature of regulation affecting the Company, the total amount of these costs is not now determinable. Compliance with existing and proposed regulation also affects the time needed to complete new facilities or to modify present facilities, and it affects the Company's rates, sales, revenues and net income, all in ways that may be substantial but are not readily calculable.

Environmental Impact Requirements

The National Environmental Policy Act of 1969 (NEPA) requires that detailed statements of the environmental effect of generation and transmission facilities be prepared in connection with various applications to the FERC, the NRC and other federal agencies for licenses or permits to construct or operate the facilities. NEPA requires that federal licensing agencies make an independent environmental evaluation of the proposed action.

NRC Nuclear Plant Licensing

As a holder of licenses to construct or operate nuclear reactors, CL&P is subject to the jurisdiction of the NRC. The NRC has broad regulatory and supervisory jurisdiction over the design, construction and operation of nuclear generating stations, including matters of public health and safety, financial qualifications, antitrust considerations and environmental impact.

After the 1979 accident at the Three Mile Island, Pennsylvania nuclear generating station (TMI), rigorous reexaminations of nuclear plant construction and operations have been undertaken by governmental commissions, industry groups and individual utilities. The NRC has promulgated numerous requirements in response to TMI, and other initiatives have resulted from the System's and the industry's own examinations. Based on engineering reviews and plant modifications completed to date, it is anticipated that modifications to the Connecticut Yankee Unit and Millstone Unit Nos. 1 and 2 costing approximately $8,000,000, $5,000,000 and $5,000,000, respectively, will be made and that the capital costs of Millstone Unit No. 3 and the Seabrook units will be increased by approximately $1,500,000 and $2,000,000, respectively. An additional $3,600,000 and $2,600,000 will also be expended by Connecticut Yankee and the System companies, respectively, for changes required in the emergency response planning and notification systems for each plant site. It is anticipated that additional changes in nuclear plant construction, including further backfitting of existing plants, and in nuclear plant operations will be ordered by the NRC. The System companies' actions and changes in NRC requirements will also result in increases in

the capital expenditures and operating costs associated with the nuclear plants in which they have entitlements. Some equipment modifications have required and may in the future require shutdowns or deratings of the plants which would not otherwise be necessary and which will result in additional costs for replacement power. The amounts of increased capital expenditures and operating costs, including costs of replacement power, may be substantial but cannot be determined at this time.

Following the TMI accident, numerous class actions and several individual actions were filed in the U.S. District Court for the Middle District of Pennsylvania and elsewhere, seeking damages as a result of that accident. If the provisions of the Price-Anderson Act are held to apply to the accident, and if total third party damage claims resulting from the accident exceed the private insurance pool coverage of $160,000,000, then the System companies would be required to pay their share of the excess. The System companies' share would be a maximum of $5,000,000 for each of the two operating Millstone units, plus their pro rata share of a maximum of $5,000,000 for each of the other operating nuclear units in which they have an ownership interest. See note 11 to financial statements for information about the Company's insurance arrangements for the costs of replacement power resulting from nuclear incidents.

An application for a full term (40 years from initial licensing) full power operating license for Millstone Unit No. 1, which is presently operating under a provisional license, is pending before the NRC. Millstone Unit No. 2 and the Yankee Atomic, Connecticut Yankee, Maine Yankee and Vermont Yankee units have full term full power operating licenses. A construction permit for Millstone Unit No. 3 was issued by the NRC in August 1974 and expires December 30, 1985. It is expected that an operating license will be obtained, or that the construction permit will be extended, before the current expiration date.

NRC construction permits for Seabrook Unit Nos. 1 and 2 were issued in 1976. On September 25, 1980 the NRC ordered the Atomic Safety and Licensing Appeal Board to reopen its record on the seismic design of the Seabrook plant, to take additional, limited evidence and to reconsider its approval of the design. A tentative hearing date of April 16, 1981 has been set. PSNH has advised the Company that it is not able to predict the outcome. The construction and licensing of these units has been subjected to lengthy delays associated with administrative proceedings, numerous lawsuits, financial constraints, work stoppages and demonstrations at the construction site. See "Operations--Joint Projects" for further information about Seabrook.

In November, 1980 the Court of Appeals for the District of Columbia Circuit ruled that, if requested, a hearing must be held before any amendment to a nuclear plant construction permit or operating license is issued. It is anticipated that this case will be appealed to the U.S. Supreme Court. If the decision is not overturned, the issuance of license amendments may result in increased costs associated with licensing

actions. Extended public hearings for some licensing actions may result in delays affecting the continued operation or start-up after refueling of nuclear plants, which would result in substantial additional costs for replacement power.

The time required to construct major generating facilities, and to obtain required licenses and regulatory approvals, compels electric utilities (including the Company) to make substantial investments in facilities before final licenses and approvals are received. Completion of each of the three nuclear generating units now under construction in which the Company is participating depends, among other things, on obtaining necessary regulatory approvals, permits and sufficient financing. Regulatory delay contributed to the cancellation of the Montague project, described under "Construction and Financing Program". While future developments could lead to cancellation of one or more of the other units, the Company considers this possibility unlikely. If any of the units were cancelled, the Company would apply to appropriate regulatory authorities for approval to amortize its share of total costs over a future period and to recover the costs through its rates. The Company cannot predict whether and to what extent such recovery would be permitted.

The effect of these matters on the scheduled in-service dates or construction costs of the three nuclear generating units in which the Company is participating, or on the operation of other nuclear units in which the Company has ownership interests, cannot accurately be predicted. They may delay or prevent construction, or require modifications or shutdowns, of the units, any of which could have a substantial adverse impact on the Company.

Water Quality Requirements

The federal Clean Water Act (CWA) requires that every "point source" discharger of pollutants into navigable waters must obtain a National Pollutant Discharge Elimination System (NPDES) permit specifying the allowable amount of its effluent, based on the constituents of its effluent. To obtain an NPDES permit, a discharger must meet technology-based effluent standards and must also demonstrate that its effluent will not cause a violation of established standards for the physical and chemical quality of the receiving waters.

The initial NPDES permits for System generating units expired in 1979. New permits have been obtained for the Company's plants. The permits will expire in January 1985, except for the permit for the Millstone units, which expires in July 1985. The permits may be reopened to reflect more stringent requirements proposed by the EPA. Compliance with NPDES requirements has necessitated substantial expenditures and may require further expenditures in the future.

The CWA requires the DEP to approve the intake structure design and thermal discharge of generating plants. All Company plants have these approvals.

In October 1980 the EPA proposed technology-based effluent standards for certain potentially toxic chemical pollutants discharged from electric generating facilities, as required by the CWA. The standards are expected to become effective in 1981. The major impact on the Company's generating units is expected to be from more stringent controls on the discharge of chlorine. Further chemical waste treatment facilities for the Company's generating plants may be required to comply with such standards.

The CWA's ultimate cost impact on the Company cannot be estimated because of uncertainties such as the impact of the proposed toxic pollutant standards. Additional modifications, in some cases extensive and involving substantial cost, may ultimately be required for one or more of the Company's generating facilities.

Air Quality Requirements

Under the federal Clean Air Act (CAA), the EPA has promulgated national ambient air quality standards for certain air pollutants, including sulfur oxides, particulate matter and nitrogen oxide. With some exceptions, the EPA has approved a Connecticut implementation plan proposed by the DEP for the achievement, maintenance and enforcement of these standards. The Connecticut plan does not allow CL&P to burn oil having more than 0.5% sulfur content. The Company is seeking a variance from this requirement. On January 20, 1981, the DEP hearing examiner issued a report recommending that CL&P be permitted to burn oil with up to 2.2% sulfur content at its plants. If the Commissioner of Environmental Protection adopts the recommendation, the actions required to obtain EPA approval are not expected to be completed before mid-1981.

EPA and Connecticut regulations also include other air quality standards, emission standards and monitoring, and testing and reporting requirements which apply to the Company's generating stations. They require that new or modified fossil fuel-fired electric generating units operate within stringent emission limits, and meet all state and federal air quality standards and regulations for the prevention of significant deterioration of air quality. These regulations could hinder or possibly preclude the construction of new or modification of existing fossil units in the Company's service area.

Toxic Substances and Hazardous Waste Regulations

Under the federal Toxic Substances Control Act (TSCA) of 1976, the EPA has issued regulations which control the use and disposal of polychlorinated biphenyls (PCBs), which are used as insulating fluids in many electric utility transformers and capacitors manufactured before TSCA prohibited any further manufacture of such PCB equipment. The Company has taken numerous steps to comply with these regulations and has incurred increased costs for disposal of such fluids and equipment that are subject to the regulations. [illegible] of these steps, CL&P and

other System companies are burning some waste oil with a low level of PCB contamination (between 50 and 500 parts per million) as supplemental fuel at HELCO's Middletown Station Unit No. 3. The EPA and DEP have approved this disposal method, but the City of Middletown, Connecticut, has sought an injunction against the method and a reversal of the DEP approval. The City's application for an injunction was denied on January 23, 1981, but the City has filed a notice of appeal with the Connecticut Supreme Court.

Disposal of fluids with a concentration of PCBs higher than 500 parts per million, or of materials (such as capacitors) that contain such fluids, must be burned in high temperature incinerators approved by the EPA. Two such incinerators have recently been approved. In 1980 the System's cost for disposing of PCB materials in a chemical waste landfill was approximately $45,000. Since most PCB materials will be sent to incinerators in the future, the Company anticipates that its PCB disposal costs will increase.

Under the federal Resource Conservation and Recovery Act (RCRA) of 1976, the generation, transportation, storage, treatment and disposal of hazardous wastes and the disposal of some nonhazardous wastes have become subject to new EPA regulations issued in 1980. The procedures by which the Company handles, stores and disposes of hazardous waste products are being revised, where necessary, to comply with these regulations.

FERC Hydro Project Licensing

System operating companies hold licenses granted under Part I of the Federal Power Act for the operation and maintenance of four existing hydroelectric projects, including the Northfield project in which CL&P has a 53% interest. They also have applications pending on five other existing projects, four of which the Company owns and operates. The FERC has held that no license is required for one other existing project, CL&P's Tunnel project. CL&P currently holds a preliminary permit from the FERC to study the feasibility of constructing a hydroelectric facility at Derby, Connecticut. The Company is also considering a number of other sites with hydroelectric potential.

Federal Power Act licenses may be issued for terms of fifty years or less as determined by the FERC. Any plant so licensed is subject to recapture by the United States or licensing to others, after expiration of the license, upon payment to the licensee of the lesser of fair value or the net investment in the project plus severance damages less certain amounts earned by the licensee in excess of a reasonable rate of return. Licenses are customarily conditioned on the licensee's development of recreational and other non-power uses at each licensed plant. Conditions may be imposed with respect to low flow augmentation of streams and fish passage facilities.

State Generation and Transmission Siting Laws

Construction or modification of electric generation and transmission facilities and certain other utility facilities in Connecticut may not be started without a certificate of environmental compatibility and public need from the Connecticut Power Facility Evaluation Council (PFEC).

The Company is faced with a DEP order to place underground the existing transmission lines at a river crossings in Connecticut. The order has been appealed to the courts, and the outcome of the proceeding cannot be predicted.

PFEC has conducted hearings on the feasibility and cost of requiring overhead transmission and distribution lines to be undergrounded as a general practice in Connecticut. If a significant part of the Company's transmission and distribution lines were required to be installed underground, substantial additional costs would be incurred. No action has been taken in this proceeding in the last several years, so its outcome is not known.

Item 2. Properties

Except for its interests in the Northfield Mountain pumped storage plant and the Seabrook plant, the Company's present utility system is located wholly within the state of Connecticut. The principal plants and other properties comprising its system, of which certain substation equipment, data processing equipment, vehicles and office space are leased, are located either on land which is owned in fee or on land, as to which the Company owns perpetual occupancy rights adequate to exclude all parties except possibly state and federal governments, which has been reclaimed and filled pursuant to permits issued by the U.S. Army Corps of Engineers. Substantially all of the property is subject to the lien of the Company's indenture securing its outstanding mortgage bonds, and to certain other liens, encumbrances and minor restrictions, none of which impairs the usefulness of such properties in the Company's business. With few exceptions, lines and mains are located on or under streets or highways, or on properties either owned or leased by the Company or occupied under rights obtained from the owners.

As of December 31, 1980, the electric generating plants of the Company and the Company's ownership interests and entitlements from the generating plants of the four Yankee regional nuclear generating companies in which the Company is one of the common stockholders were as follows:

Name, Town, Location	Type	Year Installed	Name Plate Rating (Kilowatts)	Net Capability (Kilowatts)
Millstone Plant	Nuclear	1970	350,595(a)	349,800(a)
(Waterford-Long Island Sound)		1975	482,247(a)	461,100(a)
			832,842	810,900
Montville Plant	Steam	1954-1971	489,900	492,000
(Montville-Thames River)	2 Diesels	1967	5,500	5,500
			495,400	497,500
Northfield Plant (Northfield and Erving, Massachusetts-Connecticut River)	Pumped Storage	1972-1973	448,380(a)	530,000(a)
Devon Plant	Steam	1942-1958	429,000	463,000
(Milford-Housatonic River)	Gas Turbine	1966	16,320	18,700
			445,320	481,700
Norwalk Harbor Plant	Steam	1960-1963	326,400	338,000
(Norwalk-Long Island Sound)	Gas Turbine	1966	16,320	17,000
			342,720	355,000
Shepaug Plant (Southbury-Housatonic River)	Hydro	1955	37,200	47,000

Name, Town, Location	Type	Year Installed	Name Plate Rating (Kilowatts)	Net Capability (Kilowatts)
Rocky River Plant (New Milford-Housatonic River)	Pumped Storage	1928-1952	31,000	29,000
Stevenson Plant (Monroe-Housatonic River)	Hydro	1919-1936	30,500	28,700
5 Small Hydro Plants		1903-1937	14,660	14,100
7 Gas Turbine Plants		1953-1969	153,532	172,800
Total Company Generating Plants			2,831,554	2,966,700
Regional Nuclear Generating Plants (Ownership Interests and Entitlements of the Company)				
Connecticut Yankee Atomic Power Company (Connecticut) (25% ownership interest and entitlement)	Nuclear	1968	150,075	145,000
Maine Yankee Atomic Power Company (Maine) (8% ownership interest and 7.2% entitlement)(b)	Nuclear	1972	58,193	59,600
Vermont Yankee Nuclear Power Corporation (Vermont) (6% ownership interest and 5.4% entitlement)(b)	Nuclear	1972	30,398	28,500
Yankee Atomic Electric Company (Massachusetts) (15% ownership interest and entitlement)	Nuclear	1961	27,750	26,400
Total Regional Nuclear Generating Plants			266,416	259,500
Total Generating Plants			3,097,970	3,226,200

(a) Represents Company's 53% share as tenant in common with other System companies.

(b) Ownership interests and entitlements differ due to agreements with several municipalities to purchase a portion of the generation from these plants.

As of December 31, 1980, the Company had 22 transmission substations with an aggregate capacity of 9,795,489 kVA and 192 distribution substations with an aggregate capacity of 4,502,307 kVA. Its transmission system included 226 circuit miles of overhead 345 kV lines, 876 circuit miles of overhead 115 kV lines, 63 circuit miles of overhead 69 kV lines, 40 cable miles of 138 kV submarine cable and 35 cable miles of underground 115 kV cable. The Company's distribution system included 13,093 pole miles of overhead lines and 267 conduit bank miles of underground lines. It has in service 150,195 line transformers with an aggregate capacity of 5,619,253 kVA.

As of that date the Company had 6 propane plants, 3 LNG holders, 7 gas storage holders with a total capacity of approximately 6,500 Mcf and approximately 1,747 miles of gas distribution mains. See "Operation-Gas" under "Item 1. Business".

From January 1, 1976, through December 31, 1980 the Company made gross property additions and betterments to utility plant aggregating $665,857,000 and retired or sold property having an aggregate cost of $154,785,000, resulting in net additions during that period of $511,072,000.

The Company occupies owned or leased office buildings and service buildings which house offices, storerooms and garages.

The Company's properties are well maintained and in good operating condition.

Subject to the power of alteration, amendment or repeal by the General Assembly of Connecticut and subject to certain approvals, permits and consents of public authority and others prescribed by statute, the Company, in the opinion of its counsel, has, subject to certain exceptions not deemed material, valid franchises free from burdensome restrictions to sell electricity and gas in the areas in which it is now supplying such service.

In addition to the right to sell electricity and gas as set forth above, the franchises of the Company include, among others, rights and powers to manufacture, generate, purchase, transmit and distribute electricity and gas, to sell electricity and gas at wholesale to other utility companies and municipalities and to erect and maintain certain facilities on public highways and grounds, all subject to such consents and approvals of public authority and others as may be required by law. The franchises of the Company include the power of eminent domain.

Item 3 Legal Proceedings

Six municipal electric systems in Connecticut which have been furnished firm wholesale electric service by CL&P have engaged in litigation and administrative proceedings with CL&P over rates and other matters. See "Operations - Electric" under "Item 1. Business" for information about new arrangements with three of the municipal customers (Groton, Norwich and Jewett City; the "Eastern Customers"), effective October 1, 1980.

On August 27, 1980, the United States District Court for Connecticut issued a decision denying the claims of three of the municipal customers (Wallingford, East Norwalk and South Norwalk; the "Western Customers"), in a 1973 antitrust action against Northeast Utilities, CL&P, HELCO and the Service Company. The Western Customers have appealed the decision to the United States Court of Appeals for the Second Circuit. The Eastern Customers had also been plaintiffs in that action, but their claims were settled and the action was dismissed as to them in 1979.

CL&P's R-3 wholesale rate was collected from March 2, 1976 to February 1, 1979. On November 21, 1980, the FERC issued a decision that will result in the refund of approximately $565,000, plus interest, of the revenues that were collected by CL&P under the R-3 rates. The Western Customers have applied for reconsideration.

CL&P's R-4 wholesale rates have been collected since February 1, 1979, subject to refund. The rates are estimated to increase CL&P's charges to customers by $2.3 million per year. CL&P has reached a settlement agreement with the Eastern Customers on all issues under the R-4 rate, and it has settled all issues other than rate design and price squeeze with the Western Customers. The settlements were approved by the FERC on May 5, 1980, and resulted in a refund of approximately $543,000, plus interest. The Western Customers have challenged CL&P's computation of refunds under the settlement. On February 19, 1981 the FERC affirmed an administrative law judge's decision on the challenged rate design, which the Western Customers had appealed to the full Commission. A separate hearing on price squeeze issues may follow.

PSNH and the other owners of the Seabrook project, including CL&P, have been sued by Getty Oil Company over a contract for Getty Oil Company to supply uranium for the Seabrook project. The complaint was filed on January 21, 1981 in the United States District Court for the Central District of California, alleging breach of contract and several violations of antitrust laws, including price-fixing and refusals to deal. The plaintiff seeks an order declaring that the contract is valid and enforceable, and an injunction against antitrust violations. The plaintiff also seeks damages of more than $5,000,000 plus interest and attorneys fees, to be trebled in accordance with the antitrust laws.

PSNH, CL&P and the other Seabrook owners have filed an answer and counterclaim in the California action alleging, among other things, that Getty violated the antitrust laws. In addition, on January 30, 1981, the Seabrook group brought an antitrust action against Getty and other uranium producers in the United States District Court for the Northern District of Illinois. The Seabrook group has moved to have the California and Illinois actions consolidated with pending uranium antitrust litigation in Chicago involving Westinghouse Electric Corporation, the Tennessee Valley Authority and various uranium producers.

In December 1980 the Connecticut Division of Consumer Counsel withdrew its challenge of the 1979 CL&P and HELCO rate decisions. The Division had alleged that certain discussions between members of the DPUC panel that rendered the decisions violated the Connecticut Freedom of Information Act.

The following sections of "Item 1. Business" discuss additional legal proceedings: "Operations--Joint Projects--Seabrook" for information about proceedings relating to the Seabrook nuclear electric generating units in which CL&P has an ownership interest; "Construction and Financing Program--Conservation and Coal Conversion" for information about prohibition orders that may affect the companies' oil-burning electric generating units; "Rates" for information about other rate and fuel adjustment clause proceedings; and "Regulatory and Environmental Requirements and Proceedings" for information about possible contingent liabilities of CL&P, HELCO and WMECO for damages resulting from the TMI accident, litigation over the System's plans for PCB disposal and proceedings involving river crossings of transmission lines.

Item 4. Security Ownership of Certain Beneficial Owners and Management

As of December 31, 1980, the Directors of the Company beneficially owned the following number of Common Shares of Northeast Utilities, a registered public utility holding company which holds all of the issued and outstanding Common Stock of the Company. There were 68,212,316 shares of Northeast Utilities outstanding at December 31, 1980. Each of the following represents an amount which is less than one percent of the total Common Shares outstanding.

Name	Amount of Northeast Utilities shares Beneficially Owned* by Directors
William B. Ellis	1,500
Walter F. Fee	1,313
E. James Ferland	1,682
Leon E. Maglathlin, Jr.	200
Herbert W. Sears	753
Lelan F. Sillin, Jr.	5,000
Peter M. Stern	1,424
Donald C. Switzer	2,635
Walter F. Torrance, Jr.	4,339
Anthony E. Wallace	8,333
Amount Benefically Owned* by Directors and Executive Officers as a Group (consisting of 13 individuals)	26,244

*As that term is interpreted by the Securities and Exchange Commission.

PART II

Item 5. Market for the Registrant's Common Stock and Related Security Holder Matters

All of the common stock of CL&P is owned by Northeast Utilities. There is no active market in the common stock.

The dividends paid by the Company for the past two years by quarters are shown below:

	Year	Quarterly Dividend Per Share
1979	First Quarter	$0.8775
	Second Quarter	0.8775
	Third Quarter	1.0000
	Fourth Quarter	0.9600
1980	First Quarter	0.9100
	Second Quarter	0.9800
	Third Quarter	1.3000
	Fourth Quarter	1.3200

Information with respect to dividend restrictions, which is incorporated herein by reference, is contained on page 14 of the Company's Annual Report to Stockholders as a note to the "Statements of Common Stockholder's Equity" and made a part of this report as Exhibit 13.

Item 6. Selected Financial Data

This information, which is incorporated herein by reference, is contained on page 27 of the Company's Annual Report to Stockholders which is attached and made a part of this report as Exhibit 13.

Item 7. Management Discussion and Analysis of Results of Operations and Financial Condition

This information, is contained on pages 2 through 9 of the Company's Annual Report to Stockholders, which is attached and made a part of this report as Exhibit 13.

Item 8. Financial Statements and Supplementary Data

The following financial statements of the Company, which are incorporated herein by reference are included on pages 10 through 27 of the Annual Report to Stockholders and made a part of this report as Exhibit 13.

Report of Independent Public Accountants.

Statements of Income for the years ended December 31, 1980, 1979 and 1978.

Statements of Sources of Funds for Gross Property Additions for the years ended December 31, 1980, 1979 and 1978.

Balance Sheets at December 31, 1980 and 1979.

Statements of Common Stockholder's Equity for the years ended December 31, 1980, 1979 and 1978.

Notes to Financial Statements.

Statements of Quarterly Financial Data.

Item 9. Directors and Executive Officers of the Registrant

The following information is provided with respect to each director and executive officer of the Company as of December 31, 1980. The terms of each position expire as of the Annual Meeting in 1981, except as otherwise noted.

Name	Age	Position	First Became an Officer	First Elected as a Director
Lelan F. Sillin, Jr.	62	Chairman, Chief Executive Officer; Director	4/14/69	3/20/68
Donald C. Switzer	64	Vice Chairman and Dir.	10/01/75	1/25/71
William B. Ellis	40	President, Chief Operating Officer; Director	6/15/76	6/15/76
Walter F. Fee	59	Executive Vice Pres.- Engineering & Operations; Director	10/01/75	4/23/73
E. James Ferland	38	Executive Vice Pres.- and Chief Financial Officer; Director	5/01/80	5/01/80
Anthony E. Wallace (1)	65	Executive Vice Pres.- Regional Administration; Director	4/15/64	7/01/66
William G. Counsil	43	Senior Vice President - Engineering & Operations	5/01/78	-
Leon E. Maglathlin, Jr.	54	Senior Vice President; Director	12/29/80	12/01/74
Herbert W. Sears	62	Senior Vice President - Administrative Services; Director	3/01/77	11/01/78
Walter F. Torrance, Jr.	53	Senior Vice President, General Counsel and Assistant Secretary; Director	3/01/78	4/17/78

Name	Age	Position	First Became an Officer	First Elected as a Director
Philip T. Ashton	46	Vice President-Trans. Engineering & Construction	5/01/78	-
Warren F. Brecht	48	Vice President-Management Information Systems and Controller	6/06/77	-
Carroll A. Caffrey	54,	Vice President - Human Resources	7/18/79	-
Raymond E. Donovan	50	Vice President-Customer Services	3/01/78	-
Francis L. Kinney	48	Vice President - Public Affairs	4/04/69	-
Jack R. McClendon	64	Vice President & General Manager - Gas	4/01/78	-
Leonard A. O'Connor	54	Vice President & Treas.	2/16/70	-
Walter T. Schultheis	54	Vice President-Power Supply Planning and Research	7/18/79	-
Peter M. Stern	55	Vice President - Corporate & Environmental Planning; Director	5/01/78	12/20/71
Robert W. Bishop	37	Secretary	5/01/78	-

(1) Mr. Wallace resigned as an Executive Vice President and a Director effective upon his retirement on January 1, 1981.

Name	Business Experience During Past 5 Years
Lelan F. Sillin, Jr.	Chairman since 1970[1]; responsible for the formulation of overall policy.
Donald C. Switzer	Elected Vice Chairman in 1978, previously Executive Vice President (1976) of an affiliate since 1971; responsible for engineering and operations.
William B. Ellis	Elected President in 1978, previously Vice President (1976); responsible for finance and administration. Prior to joining the Company he was a partner in the Washington, D.C. office of the management consulting firm of McKinsey & Co. as principal-in-charge[2] of the firm's utility practice.
Walter F. Fee	Elected Executive Vice President in 1978, previously Vice President (1975) of an affiliate since 1971.
E. James Ferland	Elected Executive Vice President in 1980; beginning in 1964, held a variety of engineering positions including appointment as Station Superintendent at Millstone Nuclear Power Station in 1976; in 1978 became Director-Rate Regulatory Project.

Name	Business Experience During Past 5 Years
Anthony E. Wallace	First Elected Executive Vice President in 1966.[3]
William G. Counsil	Elected Vice President in 1978; previously Plant Superintendent for the nuclear units (1974) and Project Manager for a third unit (1976).
Leon E. Maglathlin, Jr.	Elected Vice President of an affiliate in 1969 and Chief Administrative Officer of that affiliate in 1974.[4]
Herbert W. Sears	Elected Senior Vice President in 1980, having been elected Vice President in 1964.
Walter F. Torrance, Jr.	Elected Vice President in 1978; previously had been partner in the law firm of Carmody and Torrance in Waterbury, Connecticut and had represented the Company and its affiliates in regulatory and legal proceedings.[5]
Philip T. Ashton	Elected Vice President in 1978, previously Director of transmission engineering and construction of an affiliate.
Warren F. Brecht	Elected Vice President in 1977 and Controller in 1979; previously had been Assistant Secretary for Administration, U.S. Department of the Treasury.
Carroll A. Caffrey	Elected Vice President in 1979; previously Director-Industrial Relations (1973) and Director-Human Resources Group (1978).
Raymond E. Donovan	Elected Vice President in 1978; previously Director of Corporate Development of an affiliate since 1973.[6]
Francis L. Kinney	First elected a Vice President in 1974 with responsibilities including Corporate Secretary and Senior Counsel.
Jack R. McClendon	Elected Vice President in 1978; previously Division Manager since 1973.
Leonard A O'Connor	Elected Treasurer in 1970 and Vice President in 1975.[7]
Walter T. Schultheis	Elected Vice President in 1979; previously Director-Capacity Planning (1974) and Director-Research and System Planning (1977).
Peter M. Stern	Elected Vice President of an affiliate in 1968 with responsibilities for corporate and environmental planning.

Name	Business Experience During Past 5 Years
Robert W. Bishop	Elected Secretary in 1978, having been Assistant Secretary since 1977; previously had been associated with the Connecticut Energy Agency and the Connecticut Department of Planning and Energy Policy.

[1]Director of Irving Bank Corporation and its principal affiliate, Irving Trust Company, Hartford Steam Boiler Inspection and Insurance Company and Arthur D. Little, Inc.

[2]Director of CBT Corporation and its principal subsidiary, The Connecticut Bank and Trust Company.

[3]Director of Connecticut Water Service, Inc. Mohasco Corp., Society for Savings and the Connecticut Mutual Life Insurance Co.

[4]Director of Third [illegible]ional Bank of Hampden County.

[5]Director of MacDermid, Inc., The Woodbury Telephone Company and The Connecticut National Bank.

[6]Director of Central Bank for Savings.

[7]Director of Baybank Valley Trust Company.

There are no family relationships between any director or executive officer and any other director or executive officer of the Company.

Item 10. Management Remuneration and Transactions

The Company is a wholly owned subsidiary of Northeast Utilities, a registered public utility holding company. All remuneration of officers of the Company, like other subsidiaries of Northeast Utilities, is received in the form of salaries paid by Northeast Utilities Service Company.

All remuneration paid by the System and its subsidiaries during the year 19[illegible] [illegible] of the five highest paid Trustees or officers of the System or executive officers or Directors of its subsidiaries, and to all Trustees and officers of the System or executive officers or Directors of its subsidiaries as a group, appears below.

Name of Individual	Capacities in which Served (1)	Cash and Cash-Equivalent Forms of Remuneration (2)(3)
Lelan F. Sillin, Jr	Chairman of the Board and Chief Executive Officer of Northeast Utilities	$ 209,333
Donald C. Switzer	Vice Chairman of Northeast Utilities	$ 139,267
William B. Ellis	President and Chief Operating Officer of Northeast Utitilities	$ 135,767
Anthony E. Wallace	Executive Vice President of Northeast Utilities Service Company	$ 109,667
Walter F. Fee	Executive Vice President of Northeast Utilities Service Company	$ 97,000
All Trustees and executive officers of Northeast Utilities and its subsidiaries, as a group, consisting of 26 individuals as of 12/31/80.		$1,291,833

(1) Each of the named individuals also served as an officer and a Director of various subsidiaries of the System.

(2) No individuals receive benefits under life, health, hospitalization or medical reimbursement plans which are not available generally to all salaried employees.

(3) Not included are contributions by the System and its subsidiaries under the retirement plan since such contributions cannot readily be calculated for individual participants in the plan. The aggregate contributions accrued in 1980 by the System and its subsidiaries on behalf of plan participants amounted to 14.64% of the total amount paid on wages to such participants. Additional information is set forth below.

(4) Employees of Northeast Utilities and its subsidiaries, including the officers listed in the table above, are entitled to receive retirement benefits under a plan which provides for defined benefits in the event of retirement at a specified age and after a specified number of years of service, except as mentioned below in the case of Mr. Sillin. Aggregate contributions are made annually to the retirement plan for the benefit of all employees covered by the plan.

The following table shows the estimated annual retirement benefits payable under the retirement plan assuming that retirement occurs at age 65, which for the officers listed above will occur with 32, 32, 29, 32 and 28 years of credited service, respectively. The benefits as presented do not take into account any reduction for joint and survivorship annuity payments.

Annual Pension for Years of Participation Indicated

Average Annual Earnings For the Highest Consecutive 60 Months of Last 120 Months Prior to Normal Retirement	Years of Service		
	25	30	35
$ 75,000	$27,525	$ 33,030	$ 38,535
100,000	36,900	44,280	51,600
125,000	46,275	55,530	64,785
150,000	55,650	66,780	77,910
175,000	65,025	78,030	[illegible],035
200,000	74,400	89,280	1[illegible]4,160
225,000	83,775	100,530	110,625*
250,000	93,150	110,625*	110,625*

*The 1980 maximum benefit allowed under the Employee Retirement Income Security Act of 1974 (ERISA).

(5) Mr. Sillin was President of Central Hudson Gas & Electric Corporation prior to joining Northeast Utilities as President in April, 1968. A contract entered into between Mr. Sillin and Northeast Utilities Service Company at the time of his employment provides that Mr. Sillin's benefits upon retirement will be computed as if his period of service with and compensation payable from Central Hudson Gas & Electric Corporation were counted as employment with and compensation from Northeast Utilities Service Company, but that such benefits will be reduced by the value of retirement benefits payable to Mr. Sillin under Central Hudson's retirement plan. An additional accrual of $57,924 was made in 1980 to a separate reserve account to satisfy Northeast Utilities' supplementary obligation under this contract.

Directors of the Company do not receive any compensation for their service as a Director.

PART IV

Item 11. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) 1. Financial Statements:

The Report of Independent Public Accountants and the financial statements of the Company included in the Annual Report to Stockholders are incorporated by reference in Item 8.

2. Schedules:

V. Utility Plant (including intangibles and excluding Nuclear Fuel) - years ended December 31, 1980, 1979 and 1978

V. Nuclear Fuel - years ended December 31, 1980, 1979 and 1978

VI. Accumulated Provision for Depreciation of Utility Plant - years ended December 31, 1980, 1979 and 1978

VIII. Reserves - years ended December 31, 1980, 1979 and 1978

X. Supplementary Income Statement Information - years ended December 31, 1980, 1979 and 1978

All other schedules of the Company for which provision is made in the applicable regulations of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore have been omitted.

3. Listing of Exhibits:

Each document described below is incorporated by reference to the files of the Securities and Exchange Commission, unless the reference to the document is indicated by an asterisk. Documents marked with a double asterisk refer to exhibits filed in the 1980 Form 10-K of Northeast Utilities (File No. 1-5324).

Exhibit Number	Description
3	Articles of incorporation and by-laws
3.1	Charter and franchises of the Company and predecessor companies dated July 1, 1936. (Exhibit A.1, File No. 2-2477)
*3.1.1	Supplement No. 1 to Charter of the Company dated January 1, 1955.
*3.1.2	Supplement No. 2 to Charter of the Company dated October 22, 1975.
*3.2	By-laws of the Company.
4	Instruments defining the rights of security holders, including indentures
4.1	Indenture of Mortgage and Deed of Trust between CL&P and Bankers Trust Company, Trustee, dated as of May 1, 1921. (Exhibit B-2, File No. 2-2477)

4.2 Collateral Indenture and Supplemental Indenture thereto, dated as of May 1, 1921. (Exhibits B-3 and B-4, File No. 2-2477)

Supplemental Indentures dated as of:

4.3 September 1, 1936. (Exhibit B-12, File No. 2-2477)

4.4 October 20, 1936. (Exhibit B-13, File No. 2-2477)

4.5 August 31, 1944. (Exhibit B-18, File No. 2-5460)

4.6 September 1, 1944. (Exhibit B-19, File No. 2-5460)

4.7 May 1, 1945. (Exhibit B-20, File No. 2-5907)

4.8 October 1, 1945. (Exhibit B-21, File No. 2-5907)

4.9 November 1, 1949. (Exhibit B-22, File No. 2-8171)

4.10 December 1, 1952. (Exhibit B-23, File No. 2-10949)

4.11 December 1, 1955. (Exhibit B-24, File No. 2-13032)

4.12 January 1, 1958. (Exhibit B-25, File No. 2-14688)

4.13 February 1, 1960. (Exhibit B-26, File No. 2-16004)

4.14 April 1, 1961. (Exhibit 4.14, File No. 2-60806)

4.15 September 1, 1963. (Exhibit 4.15, File No. 2-60806)

4.16 April 1, 1967. (Exhibit 4.16, File No. 2-60806)

4.17 May 1, 1967. (Exhibit 4.17, File No. 2-60806)

4.18 January 1, 1968. (Exhibit 4.18, File No. 2-60806)

4.19 October 1, 1968. (Exhibit 4.19, File No. 2-60806)

4.20 December 1, 1969. (Exhibit 4.20, File No. 2-60806)

4.21 January 1, 1970. (Exhibit 4.21, File No. 2-60806)

4.22 October 1, 1970. (Exhibit 4.22, File No. 2-60806)

4.23 December 1, 1971. (Exhibit 4.23, File No. 2-60806)

4.24 August 1, 1972. (Exhibit 4.24, File No. 2-60806)

4.25 April 1, 1973. (Exhibit 4.25, File No. 2-60806)

4.26 March 1, 1974. (Exhibit 4.26, File No. 2-60806)

4.27 February 1, 1975. (Exhibit 4.27, File No. 2-60806)

4.28 September 1, 1975. (Exhibit 4.28, File No. 2-60806)

4.29 May 1, 1977. (Exhibit 4.29, File No. 2-60806)

4.30 March 1, 1978. (Exhibit 2.30, File No. 2-68807)

**4.31 September 1, 1980. (Exhibit 4.2.31)

10 Material Contracts

10.1 Stockholder Agreement dated as of July 1, 1964 among the stockholders of Connecticut Yankee Atomic Power Company. (Exhibit 13.1, File No. 2-22958)

10.2 Power Contract dated as of July 1, 1964 between Connecticut Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 13.2, File No. 2-22958)

**10.2.1 Form of Supplementary Power Contract dated as of March 1, 1978 between Connecticut Yankee Atomic Power Company and each of CL&P, HELCO and WMECO. (Exhibit 10.2.1)

**10.2.2 Form of amendment to Supplementary Power Contract dated as of August 1, 1980 between Connecticut Yankee Atomic Power Company and each of CL&P, HELCO and WMECO. (Exhibit 10.2.2)

10.3 Capital Funds Agreement dated as of September 1, 1964 between Connecticut Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 13.3, File No. 2-22958)

**10.3.1 Five Year Capital Contribution Agreement dated as of November 1, 1980 among the stockholders of Connecticut Yankee Atomic Power Company. (Exhibit 10.3.1)

**10.4 Stockholder Agreement dated December 10, 1958 between Yankee Atomic Electric Company and CL&P, HELCO and WMECO. (Exhibit 10.4)

10.5 Power Contract as amended through April 30, 1975 between Yankee Atomic Electric Company and CL&P, HELCO and WMECO. (Exhibit 5.8, File No. 2-57327)

10.6 Research Agreement between Yankee Atomic Electric Company and CL&P, HELCO and WMECO. (Exhibit D-2, File No. 2-21154)

10.7 Millstone Plant Agreement dated as of June 30, 1966 among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 13.6, File No. 2-26021)

10.7.1 Supplement to Millstone Plant Agreement dated as of December 1, 1967 by and among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 7.10, File No. 2-60806)

10.7.2	Supplement to Millstone Plant Agreement dated as of December 1, 1972 by and among CL&P, HELCO, WMECO and The Millstone Point Company. (Exhibit 7.11, File No. 2-60806)
10.8	Northfield Mountain Project Operating Agreement dated as of February 14, 1968 among CL&P, HELCO and WMECO. (Exhibit 4.11, File No. 2-30018)
10.9	Capital Funds Agreement dated as of May 20, 1968 between Maine Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 4.13, File No. 2-30018)
10.10	Power Contract dated as of May 20, 1968 between Maine Yankee Atomic Power Company and CL&P, HELCO and WMECO. (Exhibit 4.14, File No. 2-30018)
10.11	Stockholder Agreement dated as of May 20, 1968 among stockholders of Maine Yankee Atomic Power Company. (Exhibit 4.15, File No. 2-30018)
10.12	Capital Funds Agreement dated as of February 1, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.16, File No. 2-30018)
10.12.1	Amendment to Capital Funds Agreement dated as of March 12, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.17, File No. 2-30018)
10.13	Power Contract dated as of February 1, 1968 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 4.18, File No. 2-30018)
10.13.1	Amendment to Power Contract dated as of June 1, 1972 between Vermont Yankee Nuclear Power Corporation and CL&P, HELCO and WMECO. (Exhibit 5.22, File No. 2-47038)
10.14	Sponsor Agreement dated as of July 1, 1968 among the sponsors of Vermont Yankee Nuclear Power Corporation. (Exhibit 4 '6, File No. 2-30285)
**10.15	Form of Service Contract dated as of July 1, 1966 between each affiliated company of the System and the Service Company. (Exhibit 10.15)
**10.15.1	Form of Renewal of Service Contract dated as of January 1 in each year. (Exhibit 10.15.1)
10.16	Nuclear Fuel Supply Contract among CL&P, HELCO, WMECO and NNECO dated as of December 1, 1972, and first amendment. (Exhibit 7.34, File No. 2-60806)
10.16.1	Second Amendment to Fuel Supply Contract (Exhibit 7.35, File No. 2-60806)

10.17 Trust Indenture between NNECO and The Connecticut Bank and Trust Company dated as of December 1, 1972 relating to the issue of Secured Notes to finance nuclear fuel. (Exhibit 7.36, File No. 2-60806)

10.17.1 First Supplement to Trust Indenture between NNECO and The Connecticut Bank and Trust Company dated as of September 1, 1975. (Exhibit 7.37, File No. 2-60806)

10.17.2 Second Supplement to Trust Indenture between NNECO and The Connecticut Bank and Trust Company dated as of October 1, 1975. (Exhibit 7.38, File No. 2-60806)

10.17.3 Third Supplement to Trust Indenture between NNECO and The Connecticut Bank and Trust Company dated as of December 1, 1977. (Exhibit 7.39, File No. 2-60806)

10.18 Nuclear Fuel Sale Agreement between Manufacturers Hanover Trust Company, not in its individual capacity but solely as trustee of the Waterford Fuel Supply Trust, and NNECO dated as of November 15, 1977. (Exhibit 7.57, File No. 2-60806)

**10.18.1 First Amendment to Nuclear Fuel Sale Agreement between Manufacturers Hanover Trust Company, not in its individual capacity but solely as Trustee of the Waterford Fuel Supply Trust, and NNECO dated as of April 16, 1979. (Exhibit 10.18.1)

10.19 Agreement for joint ownership, construction and operation of New Hampshire nuclear generating units dated as of May 1, 1973. (Exhibit 13-57, File No. 2-48966)

10.19.1 Amendments to Exhibit 10.19 dated May 24, 1974, June 21, 1974 and September 25, 1974. (Exhibit 5.15, File No. 2-51999)

10.19.2 Amendments to Exhibit 10.19 dated October 25, 1974 and January 31, 1975. (Exhibit 5.23, File No. 2-54646)

10.19.3 Sixth Amendment to Exhibit 10.19 dated as of April 18, 1979. (Exhibit 5.4.3, File No. 2-64294)

10.19.4 Seventh Amendment to Exhibit 10.19 dated as of April 18, 1979. (Exhibit 5.4.4, File No. 2-64294)

10.19.5 Eighth Amendment to Exhibit 10.19 dated as of April 25, 1979. (Exhibit 5.4.5, File No. 2-64815)

10.19.6 Ninth Amendment to Exhibit 10.19 dated as of June 8, 1979. (Exhibit 5.4.6, File No. 2-64815)

10.19.7 Tenth Amendment to Exhibit 10.19 dated as of October 10, 1979. (Exhibit 5.4.2, File No. 2-66334)

10.19.8 Eleventh Amendment to Exhibit 10.19 dated as of December 15, 1979. (Exhibit 5.4.8, File No. 2-66492)

10.19.9 Twelfth Amendment to Exhibit 10.19 dated as of June 16, 1980. (Exhibit 5.4.9, File No. 2-68168)

10.19.10 Thirteenth Amendment to Exhibit 10.19 dated as of December 31, 1980. (Exhibit 10.6, File No. 2-70579)

10.20 Memorandum of Understanding between CL&P, HELCO, Holyoke Power and Electric Company, HWP and WMECO dated as of June 1, 1970 with respect to pooling of generation and transmission. (Exhibit 13.32, File No. 2-38177)

10.21 New England Power Pool Agreement effective as of November 1, 1971 as amended. (Exhibit 7.44, File No. 2-60806)

**10.22 Participation Agreement dated June 20, 1969 between Maine Electric Power Company, Inc., CL&P, WMECO, HELCO and HWP. (Exhibit 10.22)

**10.22.1 Supplement amending Participation Agreement dated as of June 24, 1970. (Exhibit 10.22.1)

**10.22.2 Second Supplement to Participation Agreement dated as of December 1, 1971. (Exhibit 10.22.2)

10.23 Sharing Agreement dated as of September 1, 1973 with respect to 1979 Connecticut nuclear generating unit. (Exhibit 6.43, File No. 2-50142)

10.23.1 Amendment dated August 1, 1974 to Sharing Agreement--1979 Connecticut Nuclear Unit. (Exhibit 5.45, File No. 2-52392)

10.23.2 Amendment dated December, 1975 to Sharing Agreement--1979 Connecticut Nuclear Unit. (Exhibit 7.47, File No. 2-60806)

10.24 Sharing Agreement Montague nuclear generating units dated as of September 1, 1976. (Exhibit 7.48, File No. 2-60806)

10.24.1 Agreement Among Participants in Nuclear Units for Temporary Reallocation of Capacity in Event of Delay in Units. (Exhibit 6.45, File No. 2-50142)

10.24.2 Agreement Among Participants in Nuclear Units for Sharing of Additional Capacity Made Necessary by Delay in Units. (Exhibit 6.46, File No. 2-50142)

10.25 Agreement to Transfer Ownership Shares in Seabrook Unit Nos. 1 and 2. (Exhibit 5.48, File No. 2-57327)

10.25.1 Extension Agreement to Transfer Shares in Seabrook Unit Nos. 1 and 2. (Exhibit 4.7-9, File No. 2-58271)

10.25.2 Second Extension Agreement to Transfer Shares in Seabrook Unit Nos. 1 and 2. (Exhibit 7.52-1, File No. 2-60806)

10.25.3 Agreement to Transfer Shares in Seabrook Unit Nos. 1 and 2 dated June 1, 1977. (Exhibit 7.53-1, File No. 2-60806)

10.25.4 Agreement to Transfer Shares in Seabrook Unit Nos. 1 and 2 dated November 1, 1977. (Exhibit 7.53-2, File No. 2-60806)

10.26 Lease dated as of July 1, 1970 between CL&P and The Rocky River Realty Company. (Exhibit 13.34, File No. 2-38177)

**10.27 Gas Sales Contract applicable to CD-6 rates between Conn. Gas and Tennessee Gas Pipeline Company, dated December 13, 1978. (Exhibit 10.32)

**10.28 GS-1 Service Agreement made as of the 28th day of December, 1979 by and between Distrigas of Massachusetts Corporation and Conn. Gas. (Exhibit 10.33)

**10.29 TS-1 Service Agreement made as of the 28th day of December, 1979 by and between Distrigas of Massachusetts Corporation and Conn. Gas. (Exhibit 10.34)

10.30 Agreement dated March 1, 1977 between CL&P and The Southern Connecticut Gas Company for LNG storage and Vaporization Service. (Exhibit 7.32, File No. 2-60806)

**10.31 Service Agreement dated January 9, 1979 applicable to rate schedule F-1 between Algonquin Gas Transmission Company and Conn. Gas. (Exhibit 10.36)

**10.32 Service Agreement dated January 9, 1979 applicable to rate schedule W-S-1 between Algonquin Gas Transmission Company and Conn. Gas. (Exhibit 10.37)

**10.33 Service Agreement dated January 9, 1979 applicable to rate schedule SNG-1 between Conn. Gas and Algonquin Transmission Company. (Exhibit 10.38)

**10.34 Precedent agreement for interruptible sale of base gas, dated February 17, 1981, between Conn. Gas and National Fuel Gas (Penn York Corp.). (Exhibit 10.39)

**10.34.1 Precedent agreement for interruptible sale of top system supply gas. (Exhibit 10.39.1)

**10.35 Precedent storage agreement dated August 25, 1979, between Conn. Gas and National Fuel Gas (Penn York Corp.). (Exhibit 10.40)

**10.36 Storage service agreement applicable to rate schedule S-T-B between Conn. Gas and The Algonquin Transmission Company. (Exhibit 10.41)

**10.37 Memorandum of Agreement among Boundary Gas, Inc., Conn. Gas and other utilities, dated October 6, 1980. (Exhibit 10.42)

**10.38 Precedent Agreement between TransCanada Pipelines Limited and Boundary Gas, Inc., dated October 14, 1980. (Exhibit 10.43)

**10.39 Procurement and Storage Agreement among Conn. Gas, CL&P and HELCO dated as of March 7, 1979. (Exhibit 10.44)

**10.40 Service Contract dated as of March 1, 1977 between CL&P and HELCO. (Exhibit 10.45)

**10.40.1 Form of Annual Renewal of Service Contract. (Exhibit 10.45.1)

**10.41 Extra Expense Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Millstone nuclear generating units. (Exhibit 10.46)

**10.42 Extra Expense Insurance Policy issued by Nuclear Electric Insurance Limited with respect to the Connecticut Yankee nuclear electric generating plant. (Exhibit 10.47)

**10.43 Fuel oil purchase agreement between Amerada Hess Corporation and the Service Company dated December 24, 1970. (Exhibit 10.48)

**10.44 Supplement to fuel oil purchase agreement between Amerada Hess Corporation and the Service Company dated February 22, 1977. (Exhibit 10.49)

**10.45 Memorandum of Understanding between CL&P and Connecticut Municipal Electric Energy Cooperative dated September 25, 1980. (Exhibit 10.50)

**10.46 Transmission Service Agreement between the Service Company and Connecticut Municipal Electric Energy Cooperative dated October 1, 1980. (Exhibit 10.51)

*13 Annual Report to Stockholders

(b) Reports on Form 8-K - The Company filed a report on Form 8-K as of December 31, 1980, regarding a decision by the Company to cancel the Montague Nuclear Project.

SIGNATURE

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.

THE CONNECTICUT LIGHT AND POWER COMPANY
(Registrant)

Date March 26, 1981 By /s/ William B. Ellis
William B. Ellis
President and Chief Operating Officer

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

Date March 26, 1981	By /s/ Lelan F. Sillin, Jr. Lelan F. Sillin, Jr. Chairman, Chief Executive Officer and Director
Date March 26, 1981	By /s/ E. James Ferland E. James Ferland Executive Vice President, Chief Financial Officer and Director
Date March 26, 1981	By /s/ Warren F. Brecht Warren F. Brecht Vice President and Controller (principal accounting officer)
Date March 26, 1981	By /s/ Donald C. Switzer Donald C. Switzer Director
Date March 26, 1981	By /s/ William B. Ellis William B. Ellis Director
Date March 26, 1981	By /s/ Walter F. Fee Walter F. Fee Director
Date March 26, 1981	By /s/ Leon E. Maglathlin, Jr. Leon E. Maglathlin, Jr. Director
Date March 26, 1981	By /s/ Herbert W. Sears Herbert W. Sears Director
Date March 26, 1981	By /s/ Lawrence H. Shay Lawrence H. Shay Director

Date March 26, 1981 By /s/ Peter M. Stern
Peter M. Stern
Director

Date March 26, 1981 By /s/ Walter F. Torrance, Jr.
Walter F. Torrance, Jr.
Director

THE CONNECTICUT LIGHT AND POWER COMPANY

INDEX TO FINANCIAL STATEMENTS

Schedules other than those listed above have been omitted because they are either not required or are not applicable, or because the required information is included in the financial statements or notes thereto.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS ON SCHEDULES

In connection with our examination of the financial statements included in The Connecticut Light and Power Company's Annual Report to Stockholders and incorporated by reference in this Form 10-K, we have also examined the supporting schedules listed in the accompanying index. In our opinion, these schedules present fairly, when read in conjunction with the related financial statements, the financial data required to be set forth therein, in conformity with generally accepted accounting principles, which, except for the change (with which we concur) in accounting for the allowance for funds used during construction as indicated in Note 1 of Notes to Financial Statements, have been applied on a consistent basis.

ARTHUR ANDERSEN & CO.

Hartford, Connecticut,
February 20, 1981.

THE CONNECTICUT LIGHT AND POWER COMPANY
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Utility Plant in Service					
Electric	$1,411,106	$ 47,547	$ 8,833	$ 23 (3)	$1,449,843
Gas	125,549	14,355	1,855	(7)(4)	138,042
Construction Work in Progress					
Electric	318,730	94,126 (1)	-	(13,735)(6) (22)(5)	399,099
Gas	2,208	2,318 (1)	-	-	4,526
Utility Plant Held for Future Use					
Electric	967	556	-	(2)(2)	1,521
TOTAL OWNED	$1,858,560	$158,902	$10,688	$(13,743)	$1,993,031

(1) Net increase (decrease) during the year.
(2) Transfer between Nonutility Property and Utility Plant Held for Future Use.
(3) Adjustment of prior year retirement.
(4) Transfer between Utility Plant in Service and Nonutility Property.
(5) Sale of substation.
(6) Canceled Nuclear Project.

THE CONNECTICUT LIGHT AND POWER COMPANY
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1979
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
OWNED PROPERTY					
Utility Plant in Service					
Electric	$1,385,778	$ 36,737	$10,257	$ ([illegible]05)(2) 53 (3)	$1,411,106
Gas	120,646	5,598	1,889	1,205 (2) (11)(6)	25,549
Construction Work in Progress					
Electric	288,796	71,548 (1)	-	(41,416)(5) (198)(4)	318,730
Gas	1,325	883 (1)	-	-	2,208
Utility Plant Held for Future Use					
Electric	712	255	-	-	967
TOTAL OWNED	$1,797,257	$115,021	$12,146	$(41,572)	$1,858,560

(1) Net increase (decrease) during the year.
(2) Transfer between electric and gas property.
(3) Adjustment of prior year retirement.
(4) Sale of substation.
(5) Sale of 7% interest of 11.5% ownership in Seabrook.
(6) Transfer between Utility Plant in Service and Nonutility Property.

THE CONNECTICUT LIGHT AND POWER COMPANY
UTILITY PLANT (INCLUDING INTANGIBLES AND EXCLUDING NUCLEAR FUEL)
YEAR ENDED DECEMBER 31, 1978
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
OWNED PROPERTY					
Utility Plant in Service					
Electric	$1,177,832	$69,[illegible]8	$12,979	$ 76 (2) 151,008 (4) (9) (3) 2 (5)	$1,385,778
Gas	107,776	4,191	562	9,231 (4) 10 (3)	120,646
Construction Work in Progress					
Electric	259,642	38,755 (1)	-	2,008 (4) (2,625) (6) (2,762) (7) (6,222) (8)	288,796
Gas	2,090	(824) (1)	-	59 (4)	1,325
Utility Plant Held for Future Use					
Electric	559	229	-	(76) (2)	712
TOTAL OWNED	1,547,899	112,199	13,541	150,700	1,797,257
LEASED PROPERTY					
Utility Plant in Service					
Electric	145,894	6,922	1,808	(151,008) (4)	-
Gas	8,600	684	52	(9,232) (4)	-
Construction Work in Progress					
Electric	2,965	(958) (1)	-	(2,007) (4)	-
Gas	320	(261) (1)	-	(59) (4)	-
TOTAL LEASED	157,779	6,387	1,860	(162,306)	-
TOTAL	$1,705,678	$118,586	$15,401	$ (11,606)	$1,797,257

(1) Net increase (decrease) during the year.
(2) Transfer between Utility Plant in Service and Utility Plant Held for Future Use.
(3) Transfer between electric and gas property.
(4) Transfer of leasehold improvements between owned and leased property. This resulted from the purchase of property formerly leased from Connecticut Railway and Lighting Company.
(5) Adjustment of prior year retirement.
(6) Sale of substation.
(7) Sale of .5% interest of 12% ownership in Seabrook.
(8) Sale and lease back of substation equipment and buildings.

THE CONNECTICUT LIGHT AND POWER COMPANY
NUCLEAR FUEL
YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978
(Thousands of Dollars)

COL. A Classification	COL. B Balance at beginning of period	COL. C Additions at cost	COL. D Retirements	COL. E Other Changes-Add (Deduct)-Describe	COL. F Balance at close of period
Year Ended December 31, 1980					
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$11,095	$10,790	$ -	$ -	$21,885
Accumulated provision for amortization of nuclear fuel assemblies	(1,900)	-	-	5,057 (3) (3,157) (2)	-
	$ 9,195	$10,790	$ -	$ 1,900	$21,885
Year Ended December 31, 1979					
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$ 7,288	$ 6,420	$2,613 (1)	$ -	$11,095
Accumulated provision for amortization of nuclear fuel assemblies	-	-	-	(1,900) (2)	(1,900)
	$ 7,288	$ 6,420	$2,613	$(1,900)	$ 9,195
Year Ended December 31, 1978					
Nuclear fuel in process of refinement, conversion, enrichment and fabrication	$ 5,202	$ 2,209	$ 123 (1)	$ -	$ 7,288

(1) During 1979 and 1978, CL&P sold a portion of its ownership in the Seabrook Plant being built in New Hampshire and the related nuclear fuel in process.
(2) Reclassification of nuclear fuel disposal costs.
(3) Reversal of the reclassification of nuclear fuel disposal costs.

S-6

THE CONNECTICUT LIGHT AND POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT
YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978
(Thousands of Dollars)

COL. A Description	COL. B Balance at beginning of period	COL. C Additions Charged to Costs and Expenses	COL. D Retirements	COL. E Other Changes- Add (Deduct)- Describe	COL. F Balance at close of period
Year Ended December 31, 1980					
Electric	$381,879	$48,312	$ 9,771	$ 442 (1)	$420,862
Gas	22,075	3,972	1,877	120 (1)	24,290
TOTAL	$403,954	$52,284	$11,648	$ 562	$445,152
Year Ended December 31, 1979					
Electric	$341,569	$47,709	$ 8,491	$1,092 (1)	$381,879
Gas	20,646	3,216	1,967	180 (1)	22,075
TOTAL	$362,215	$50,925	$10,458	$1,272	$403,954
Year Ended December 31, 1978					
Electric	$304,636	$46,999	$11,796	$1,703 (1) 27 (2)	$341,569
Gas	18,178	2,907	780	274 (1) 67 (2)	20,646
TOTAL	$322,814	$49,906	$12,576	$2,071	$362,215

(1) Depreciation charged to Transportation and Fuel Stock Clearing Accounts.
(2) Termination of lease with Connecticut Railway & Lighting Corporation.

Schedule VI

THE CONNECTICUT LIGHT AND POWER COMPANY
RESERVES
YEAR ENDED DECEMBER 31, 1980
(Thousands of Dollars)

Schedule VIII

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$2,060	$3,578	$ -	$3,455 (a)	$2,183
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$ 995	$1,566	$ -	$1,502 (c)	$1,059
Medical insurance (e)	936	5,738	-	5,594 (d)	1,080
TOTAL	$1,931	$7,304	$ -	$7,096	$2,139

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.

(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.

(c) Principally payments for various injuries and damages and expenses in connection therewith.

(d) Principally payments for various employee medical expenses and expenses in connection therewith.

(e) Provided to cover claims for employee medical insurance.

Schedule VIII

THE CONNECTICUT LIGHT AND POWER COMPANY
RESERVES
YEAR ENDED DECEMBER 31, 1979
(Thousands of Dollars)

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
		(1)	(2)		
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$1,899	$1,663	$ -	$1,502 (a)	$2,060
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$ 991	$ 972	$ -	$ 968 (c)	$ 995
Medical insurance (e)	-	3,159	-	2,223 (d)	936
TOTAL	$ 991	$4,131	$ -	$3,191	$1,931

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.

(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.

(c) Principally payments for various injuries and damages and expenses in connection therewith.

(d) Principally payments for various employee medical expenses and expenses in connection therewith.

(e) Provided to cover claims for employee medical insurance.

THE CONNECTICUT LIGHT AND POWER COMPANY
RESERVES
YEAR ENDED DECEMBER 31, 1978
(Thousands of Dollars)

COL. A	COL. B	COL. C		COL. D	COL. E
		Additions			
Description	Balance at Beginning of Period	(1) Charged to Costs and Expenses	(2) Charged to Other Accounts	Deductions-Describe	Balance at End of Period
RESERVES DEDUCTED FROM ASSETS TO WHICH THEY APPLY:					
Reserves for uncollectible accounts	$1,716	$2,808	$ -	$2,625 (a)	$1,899
RESERVES NOT APPLIED AGAINST ASSETS:					
Injuries and damages (b)	$ 993	$ 747	$ -	$ 749 (c)	$ 991

(a) Amounts charged off as uncollectible after deducting customers' deposits and recoveries of accounts previously charged off.

(b) Provided to cover claims for injuries to employees, for workmen's compensation and for bodily injury to others and property damage.

(c) Principally payments for various injuries and damages and expenses in connection therewith.

THE CONNECTICUT LIGHT AND POWER COMPANY
SUPPLEMENTARY INCOME STATEMENT INFORMATION
YEARS ENDED DECEMBER 31, 1980, 1979 AND 1978
(Thousands of Dollars)

Column A	Column B		
Item	Charged To Costs And Expenses		
	1980	1979	1978
Taxes, other than income taxes charged to expense:			
State gross receipts	$34,170	$27,361	$22,338
Real and personal property	23,075	19,231	19,573
Payroll and Other	4,809	4,152	3,279
Total	$62,054	$50,744	$45,190

Items other than those disclosed above have been omitted because either they are not applicable, the required information has been presented in the financial statements or notes, thereto, or such amounts are less than 1 percent of total revenues.