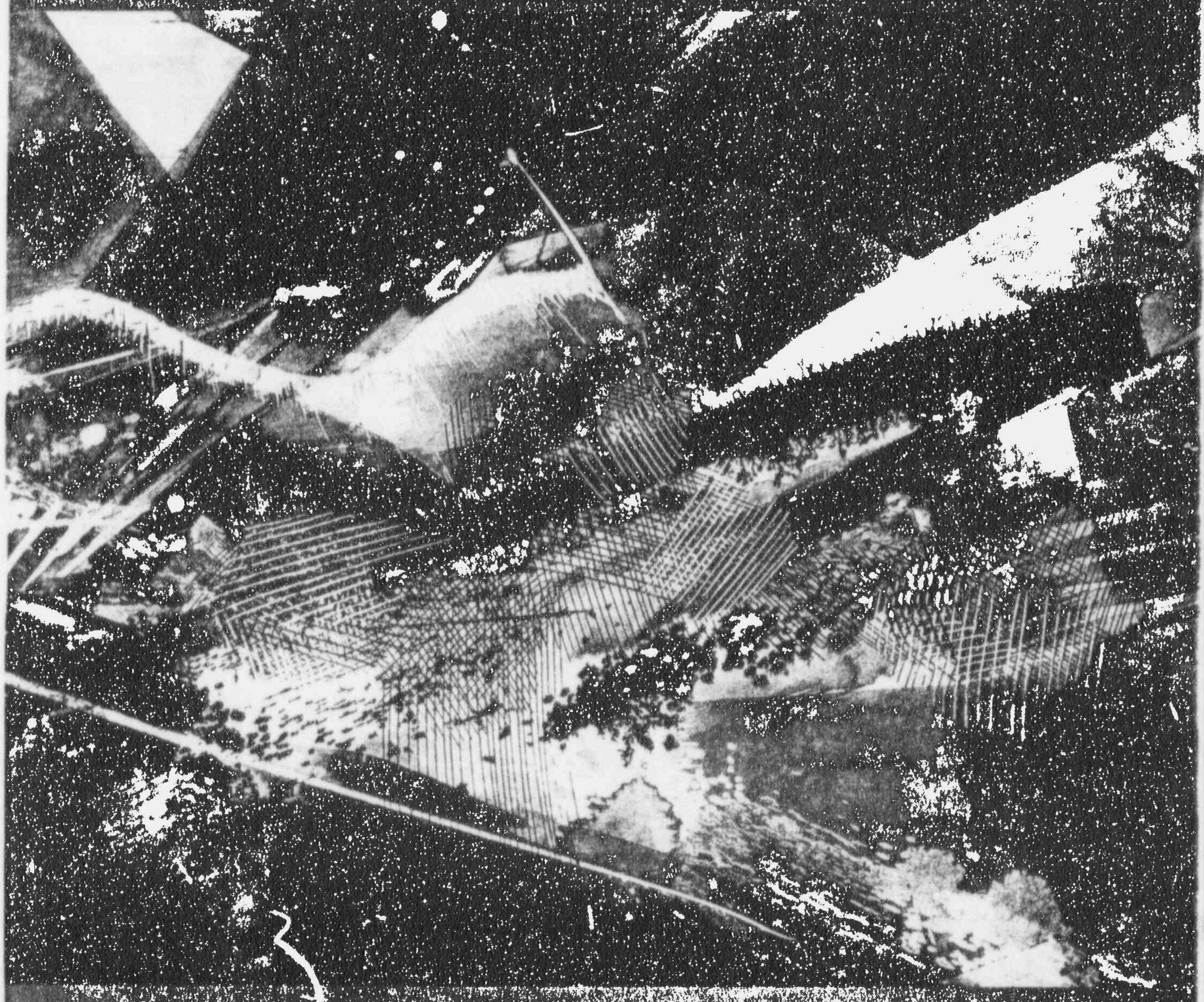
Massachusetts Municipal Wholesale Electric Company



1993 Annual Report

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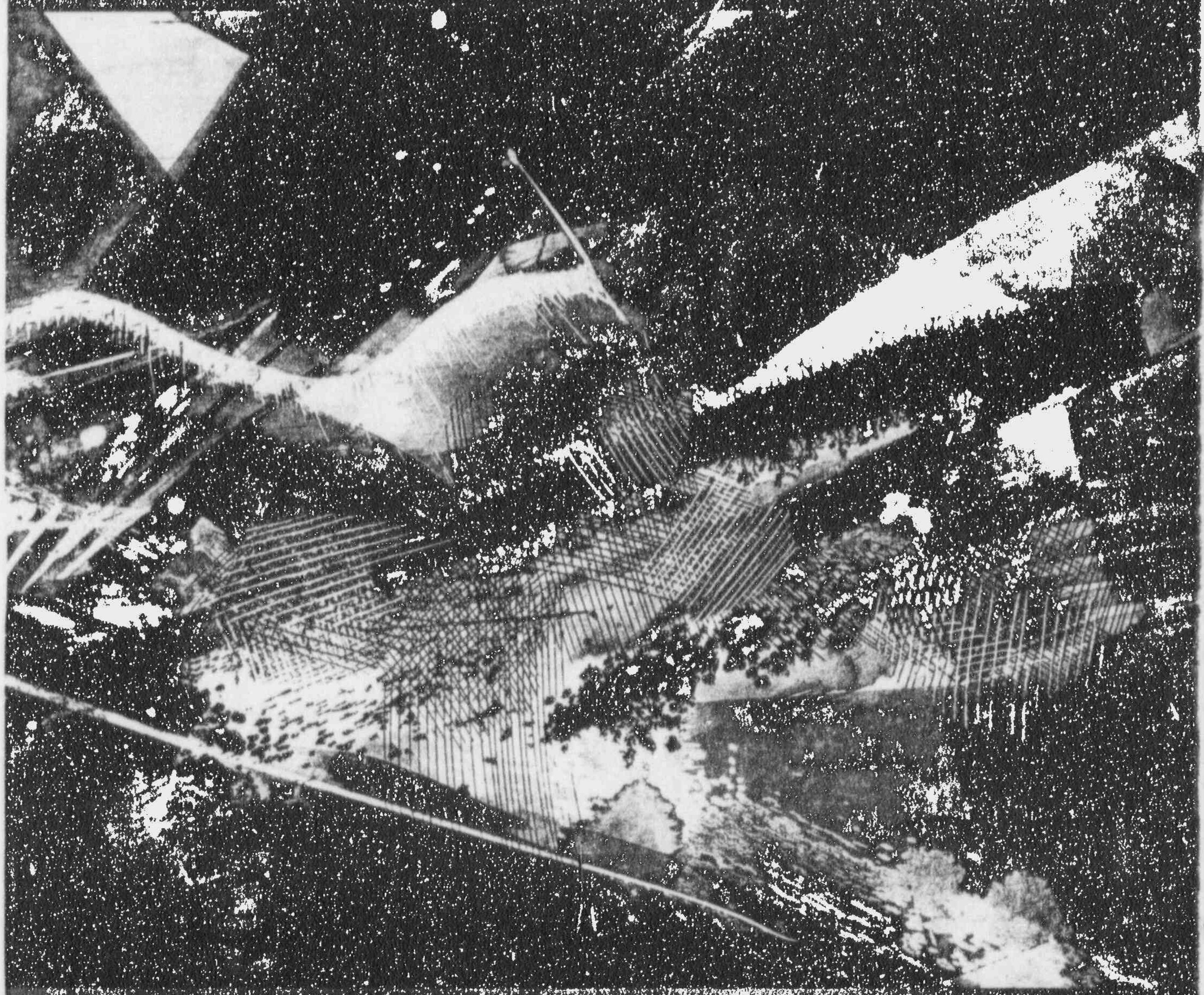


1993 Annual Report

"Good business is the best art"

Andy Warhol, *Time*, July 1975.

We have tried to provide our readers with some of the best art – both business and traditional – in this year's annual report.

We thank the following artists for their contributions to the report: James Hendricks, Marion Brown, Marjory Lehan, Jan Norman, and Janet Fredericks.

We also thank William Baczek, Gallery Director of the Hart Gallery in Northampton, Massachusetts for his assistance in choosing the artwork, and Stephen Petegorsky of Northampton, Massachusetts for photographing the artwork in preparation for printing.

A Letter from the MMWEC Management

It is with great pride in the organization's accomplishments over the past year that we present this Annual Report of the Massachusetts Municipal Wholesale Electric Company (MMWEC). With the support of its member utilities, project participant utilities, board of directors and staff, MMWEC added strength and stability to its core operations through a number of financial, legal, power supply and other achievements during the year.

In recognition of these achievements, Moody's Investors Service upgraded MMWEC's credit rating from Baa1 to A in January 1994. It is significant to note that the upgrade came after Moody's announced the application of stricter standards in its reviews of electric utilities due to risks associated with increasing competition in the industry.

Two new refunding bond issues, in April 1993 and March 1994, have fortified the financial positions of MMWEC and its project participants. Power costs for MMWEC participants have dropped by more than $850 million as a result of MMWEC's refunding program, which was initiated in 1992. Declining power costs have enabled participants to reduce their rates to the point where they are lower than or very competitive with the rates of Massachusetts' investor-owned utilities. This has given municipal utilities more flexibility and options as they work to address a number of competitive issues.

The average interest cost of MMWEC's outstanding debt has dropped from about 9.8 percent to 5.9 percent as a result of the refunding program, reducing annual interest costs by approximately $35 million.

Litigation of transmission access and pricing issues before the Federal Energy Regulatory Commission (FERC) resulted in several significant victories for MMWEC and Massachusetts municipal

Edla Ann Bloom

Edla A. Bloom, *President*

utilities during 1993. The arguments of MMWEC and others in the Northeast Utilities (NU) transmission tariff case resulted in a FERC order that expands access to NU's transmission system, the largest in New England, and reduces proposed rates for firm transmission service by about 36 percent, from \$22.55 to \$14.39/kW/year. The March 1993 FERC order in the NU case, which has yet to become final, as well as other FERC pronouncements on transmission access and pricing, reflect the success of municipal utility efforts to restrict the market power of transmission owners.

As the FERC continues its efforts to resolve transmission issues, every victory for MMWEC and the municipals will enhance their competitive position because the municipals, which own very little transmission capacity, rely on access to transmission at reasonable rates to keep their power costs as low as possible.

In other litigation, MMWEC has closed the books on challenges to the validity of its power sales contracts, which generate the funds used by MMWEC to pay its bondholders. With the contract disputes resolved in MMWEC's favor, and related litigation also coming to a close, the company's legal budget is shrinking. In addition, more stable and productive relationships between MMWEC and its participants are being developed, increasing the opportunities for cooperative action to address common needs.

The existing power supply of MMWEC's members and project participants — a diverse mix of nuclear, oil, natural gas, hydro and other resources — is adequate to meet their needs through the late 1990s. The units in MMWEC's power supply projects have proven reliability records and are scheduled for operation well into the next century. To help ensure successful future

R. E. Slattery

Richard E. Slattery, *Chairman*

operations, MMWEC has stepped up its project oversight activities, through which unit costs and operations are closely monitored.

With the effective date of new air quality regulations approaching, MMWEC has equipped its Stony Brook power plant with new combustion equipment that has dramatically reduced emissions of nitrogen oxide from the plant. Installation of this equipment, completed during a plant outage late in 1993, is part of a broader plan to bring Stony Brook into compliance with the 1990 amendments to the federal Clean Air Act and related Massachusetts regulations. MMWEC also has taken bids on a project to expand the natural gas generating capability of Stony Brook by building a pipeline linking the plant to the interstate natural gas pipeline system. Increased use of the cleaner-burning natural gas, compared to the No. 2 oil also used at the plant, would augment environmental compliance plans and reduce Stony Brook's energy costs at the same time.

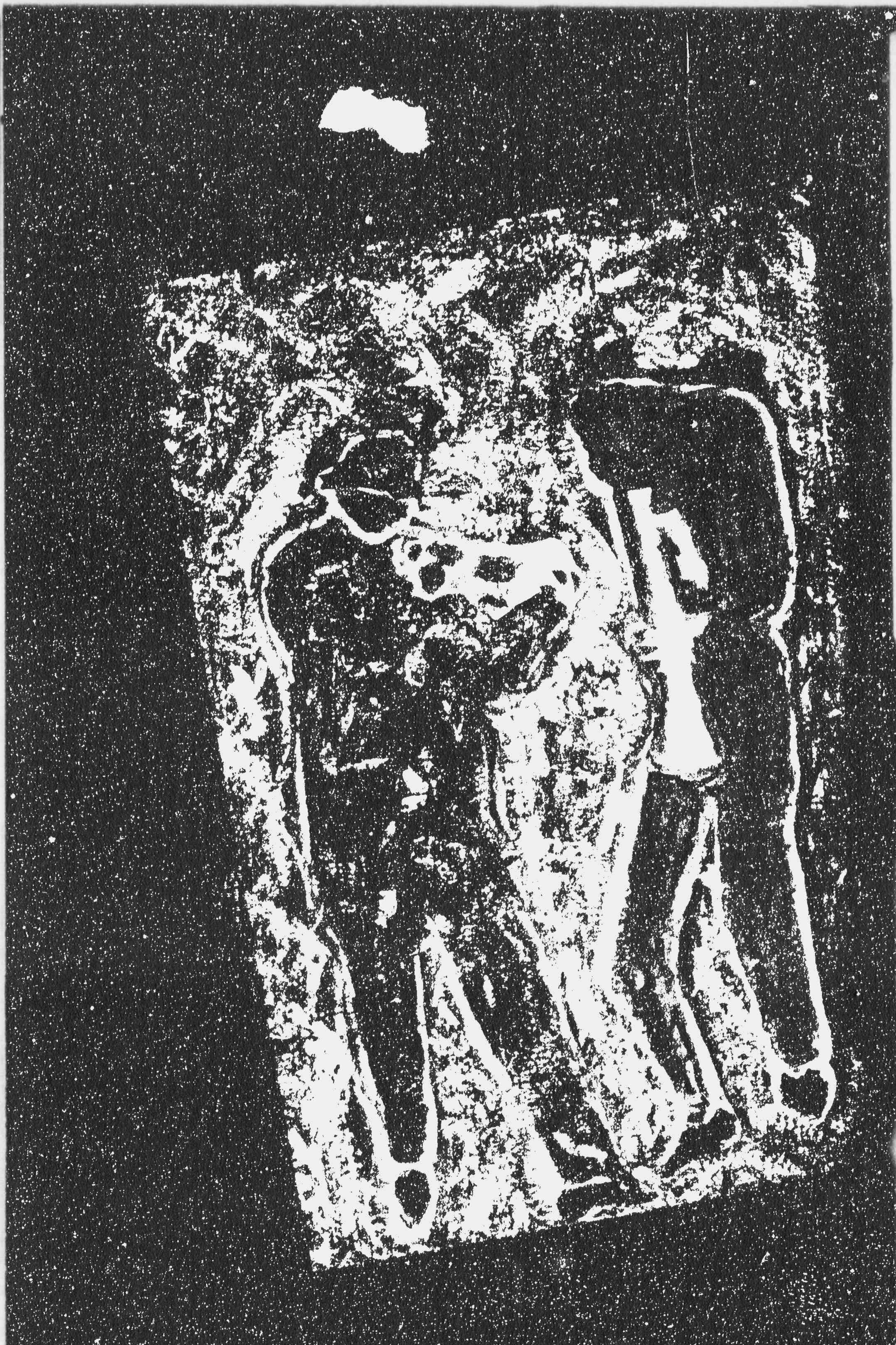
All of this is occurring in an improving Massachusetts economy, which helped to produce a 2.3 percent increase in electricity use among MMWEC's member utilities in 1993. This compares with a 1.6 percent increase for the New England region. After several years of very little growth in electricity use, the 1993 increase has boosted member revenues and is an encouraging sign of economic recovery.

Given these many positive developments, MMWEC and its Massachusetts municipal utilities are in good position to handle the increasing competition facing electric utilities today. But there is more to be done, and work to improve the competitive position of municipal utilities is ongoing through the Municipal Electric Association of Massachusetts, an organization of all 40 Massachusetts municipals, as well as through MMWEC.

To foster a better understanding of the issues associated with increased competition, this year's Annual Report contains comments from a select group of people who view these issues from regulatory, financial, government, economic, and utility perspectives. For their contributions to this report, we extend our thanks to Stephen J. Remen, Massachusetts' commissioner of energy resources; Kenneth Gordon, chairman of the Massachusetts Department of Public Utilities; Paul L. Joskow, professor of economics at the Massachusetts Institute of Technology; Leonard S. Hyman, first vice president at Merrill Lynch; Robert F. Wolff Jr., executive director of the New England Power Pool; and David W. Penn, director of policy analysis for the American Public Power Association.

David A. Sjosten

David A. Sjosten, *General Manager*



The electric power industry in New England and the rest of the United States (indeed the rest of the world) is going through a process of fundamental change. The most important force for change and the primary arena of policy discussion involves the future role of competition in the industry.

Should we expand and improve upon changes that have increased wholesale power market opportunities? Should we introduce "retail wheeling" and related types of retail market competition? If we do, how can we ensure that it promotes improved efficiency and lower prices for consumers?

On the wholesale competition front, the expansion of non-utility generating (NUG) capacity and the rapid growth of a healthy independent power sector has been impressive. Unfortunately, the potential benefits from wholesale market competition have not yet been fully reflected in electricity prices. The primary problem has been that utilities have too often found themselves with contracts for too much NUG capacity at too high a price. In part, this problem has resulted from honest forecasting errors regarding future load growth and natural gas prices. But these inevitable problems have been exacerbated by poor regulatory rules and procedures governing generation resource procurement and the growing politicization of the generation procurement process.

We should be working to make reforms that will improve the performance of wholesale power markets so that they provide greater real benefits for consumers. A major improvement would result from reforms aimed at simplifying and depoliticizing the generation resource procurement process and introducing incentive-based regulations that provide good incentives for utilities to acquire the most economical power supplies, subject of

Paul L. Joskow, Professor of Economics
Massachusetts Institute of Technology

course to current and expected future environmental regulations.

It is also desirable to continue efforts to develop fair and efficient transmission pricing and contracting rules and for fully integrating NUGs into the New England Power Pool so that they can obtain the benefits of membership and bear the associated costs and responsibilities.

More controversial is the growing movement to expand competitive opportunities for retail customers by requiring utilities to "unbundle" generation, transmission and distribution service so that retail customers can shop for their power needs in a competitive power market rather than buying all of their power from their local private or municipal utility.

"Others see retail wheeling as a way to discipline regulatory and political behavior that too often views the regulated monopoly as a convenient off-budget mechanism to finance a variety of social and political goals."

The primary motivation of many retail wheeling proponents is to take advantage of the temporary excess capacity situation and the unanticipated low prices of natural gas to get cheaper power in the wholesale market than they can get from their local utility at traditional cost-based rates. Others see retail wheeling as a way to discipline regulatory and political behavior that too often views the regulated monopoly as a convenient off-budget mechanism to finance a variety of social and political goals. This kind of "taxation by regulation" cannot survive in a fully competitive system. Finally, some see a fully competitive electricity market with both wholesale and retail competition as a way to achieve real long-run savings in the costs of supplying electricity.

Whatever the motivations for retail wheeling, one thing is clear. It is easy to introduce retail wheeling in a way that will lead to inefficiencies and inequities, benefiting a few, but burdening many. It is more difficult to introduce retail wheeling in a way that will promote real cost savings and efficiency improvements and provide for an equitable transition from the old regime to the new one.

An efficient retail wheeling regime will require fundamental changes in the way we think about electricity and the public service obligations that utilities have. In a well-functioning competitive electricity market, electricity will be a commodity like any other commodity. Rules, regulations and public service obligations that regulators and politicians in New England have grown to know and love - integrated resource planning, subsidies for energy conservation, low-income rates, environmental adders, etc. - will either be unsustainable or will need to be substantially redesigned to be compatible with a full competitive system.

Federal jurisdiction over the industry will inevitably supplant state jurisdiction as large regional market areas that span many states provide the efficient expanse of competitive electricity markets. Major structural changes will be required to provide the market institutions and market rules that are necessary to make competition work effectively and efficiently. Transition mechanisms must be developed to deal with the costs of sunk investments and contractual commitments made under existing regulatory rules.

Retail wheeling will only accrue to the benefit of all consumers if we can find the political will to mount the massive, time-consuming effort required to design and create the new institutional and transition arrangements necessary to move toward and support a fully competitive power market. A necessary, but not sufficient, condition for creating these new institutional and transition arrangements is a shared vision for the future of the industry, and cooperation among the nearly 100 utilities in New England and the state and federal agencies who regulate them to realize it.

MMWEC's View – *Sweeping changes in utility regulation, spurred by political and legislative action, are increasing competition in the electric utility industry. New laws and regulations governing transmission access, non-utility generators and resource acquisition, among other things, are transforming the way utilities do business.*

Massachusetts municipal utilities, individually and through their participation in MMWEC, the Municipal Electric Association of Massachusetts, the Northeast Public Power Association, and the American Public Power Association, have taken an active role in shaping these laws and regulations. At both the state and federal level, municipal utilities have been meeting with legislators and participating in regulatory proceedings to ensure that the interests and needs of municipal systems are given fair consideration.

Actions planned for the coming year to support existing efforts include establishing closer working relationships with legislators, regulators and key special interest groups. Also planned is a campaign intended to educate policymakers about the economic and social benefits of public power.

As a result of these and other activities, the collective force of municipal utilities will be present as the policies that shape the future evolve.

"Transition mechanisms must be developed to deal with the costs of sunk investments and contractual commitments made under existing regulatory rules."

Robert F. Wolff Jr., Chief Executive
New England Power Pool

The electric utility industry has evolved in a steady and gradual fashion over the last century, punctuated by key events that changed the course of the industry. Today, with the emergence of competition, the very core of the industry is being challenged by new ways of doing business. Unfortunately, a lack of coordination among the forces for change is making the transition extremely difficult for electric utilities.

In its infancy, few could envision the ultimate size or importance of the utility industry, and very little regulation was applied. As the industry came into adolescence, regulation was used mainly to protect the public from those who would take advantage of opportunities for monopolistic abuse. The rapidly increasing demand for electricity constantly drove the industry to the limits of both control and production hardware. As the industry matured, improvements in technology carried it into and through the 1950s and '60s. With prices stable and the supply of electricity keeping pace with demand, there was little need for regulatory involvement in the way the business was run.

Then came the oil crises of the '70s and the reality of exploding prices. Acting in their traditional roles, regulators and utilities were unable to convince the public of the need to either change its energy habits or accept the consequences associated with the increased cost of fuel. Both the industry and its regulators were stuck between the proverbial rock and hard place. The alternative was to begin exploring different ways of doing business.

Thus, as middle age approached, the industry entered a state of turmoil. First we looked at working existing equipment harder to meet rising demand with minimal investment. Next we explored less costly, unconventional means of meeting the load. Then came a variety of "peak shaving" efforts to control peak demand, followed by a proliferation of demand-management and conservation programs.

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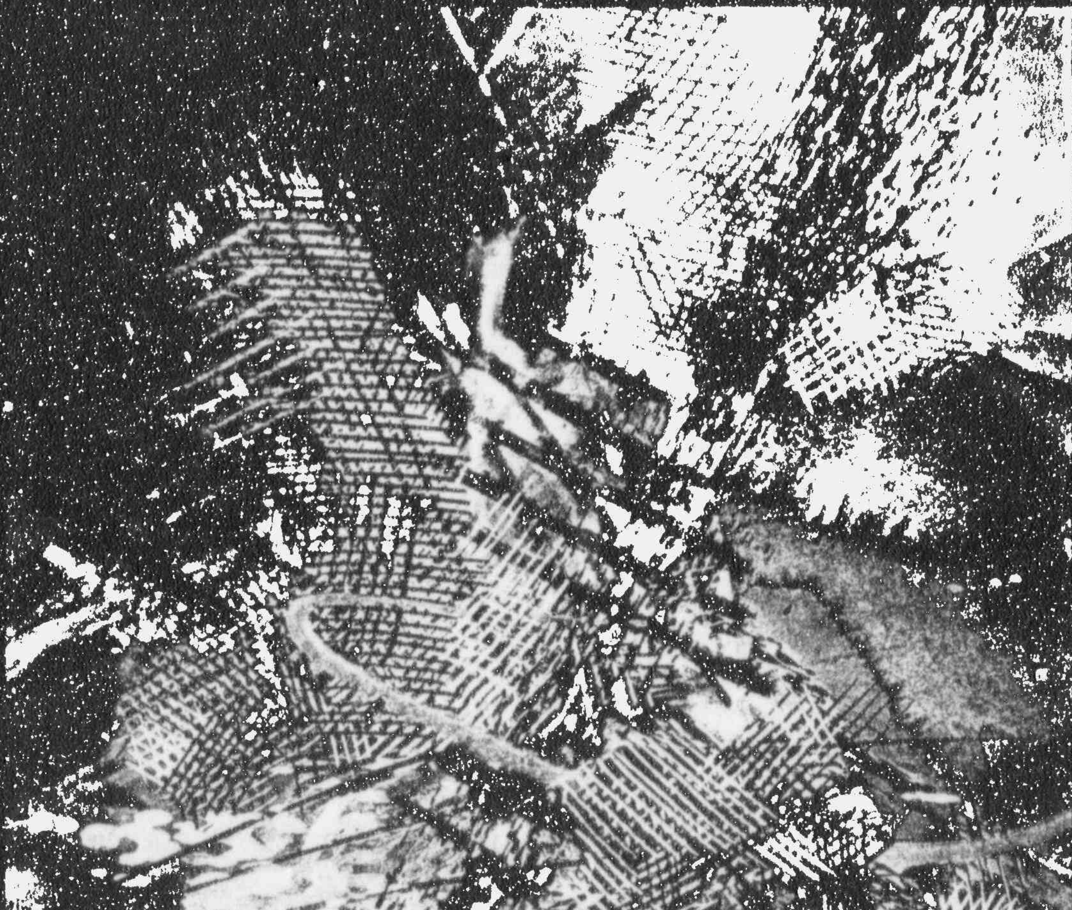


Now, in a movement that carries as many risks as potential benefits, the industry is being moved toward competition with the hope that the public will accept the price of electricity as long as it results from a competitive market place.

Growth of the non-utility industry has resulted in calls for increased access to the transmission system and has increased the pressure for retail wheeling. We are looking at dispatching power plants based on economics and emissions rather than just economics; utilities are marketing emissions reduction credits; non-utility power brokers are reaching into electricity markets; and there is talk of segmenting the utility industry into generation, transmission and distribution companies. These are only a few of the changes and issues that are shaking the traditional business foundation of electric utilities.

"The pressure on utilities to cut costs to meet competition can put equal pressure on the reliability of the electric power system."

Many proposals for change raise extremely complex and conflicting concepts. These concepts are not naturally compatible, meaning that considerable experience and wisdom will be required to meld them into an effective and efficient system designed to meet the best interests of our customers. Over the past century, as electric utilities grew to maturation, an interdependency has developed that is reflected in the thousands of pages of rules governing utility operations. Changing one operating procedure often has a ripple effect throughout the entire system. There are many conflicts and priority issues that need to be resolved if the evolution to a more competitive industry is to be successful. And it will take time.

Further complicating the issue are the efforts of several levels of regulation and legislation. In response to these efforts, utilities, their reliability councils and power pools are attempting to move into the next generation in a way that preserves traditional economics and reliability. While willing to accept these challenges, there is growing concern over adopting so many basic and conflicting

MMWEC's View – *A single municipal utility would be overcome quickly by the costs and time required to fully participate in the far-reaching debate over issues associated with increased competition in the electric utility industry. Working together, however, Massachusetts municipal utilities are not only participating in the debate; they are making a difference.*

With power supply, environmental and other competitive issues advancing rapidly, there is a growing sense of unity and common purpose among the state's municipal systems. A number of issue-oriented alliances have developed, and there has been a general resurgence of confidence in the strength and effectiveness of joint action.

MMWEC, as the official joint action agency for Massachusetts municipal utilities, often plays a key role in these alliances, coordinating legal and financing activity, researching issues and developing positions. At the same time, municipal systems that are not members of MMWEC are getting more involved, sharing in the costs and decision-making associated with these initiatives, and expanding the base of joint action in Massachusetts.

changes all at once, since the outcome of these changes cannot be fully understood prior to implementation. In addition, the introduction of non-utility suppliers has raised a number of equity issues, including the need for utilities and non-utilities to share the costs of conservation, clean air and an adequate transmission system.

The pressure on utilities to cut costs to meet competition can put equal pressure on the reliability of the electric power system. One example of this pressure is the temptation to cut maintenance costs at generating plants in years of lean cash flow. As the inevitable impact begins to take its toll on generator availability, the emphasis shifts back to increased maintenance. There are many difficult choices ahead for utilities, regulators and consumers as each search for a balance between power costs, reliability, environmental impacts, conservation and other new components of the power supply equation.

The lack of a blueprint for change – and the need for one – is evidenced in the growing divergence in the way utilities are responding to their new challenges.

Despite this period of turmoil, one thing is clear: utility leaders and regulators are both committed to providing a system that can meet the needs of our customers.

During the 1980s, the watchwords in electricity regulation were demand-side management, conservation and the development of a wholesale electricity market based on competition among independent power producers. The watchwords of the '90s appear to be "open transmission."

The avowed aim of federal policy is to foster a full flowering of the competitive wholesale market that was emerging during the '80s. The lesson of the mid-1990s, however, is likely to be that once Pandora's competition box has been opened, unanticipated developments may emerge. Competitive markets are hard to limit when customers see others making choices, and can see no technical reason why they should not be able to join the party as well.

"Joining the party" translates in electricity jargon to "retail wheeling." Retail wheeling is nothing more than an arrangement whereby individual end users of electricity are able to select their preferred supplier, based on price. Viewed in this light, retail wheeling is simply an extension of the expanded consumer choice that has been associated with

Kenneth Gordon, Chairman
Massachusetts Department of Public Utilities

deregulation in other traditionally regulated areas.

And, in fact, it is important that this perspective not be lost in policy discussions of retail wheeling. The current system has been based on a presumption that the supply of electricity is a natural monopoly exhibiting both economies of scale and economies of scope across the different customer classes.

One of the things we will discover as options appear for particular customers, particularly large customers, is whether there are limits to economies of scope and scale. We will also learn the limits regulators face in allocating overhead costs among different classes of customers.

In New England, these trends are today complicated by substantial excess capacity. For short-term contracts, at least, options may appear that are very attractive indeed, compared to the full long-run embedded cost options typically available to a captive utility customer. This short-run availability of lower rates drives customers to look for alternatives even more vigorously than they might in a long-term setting.

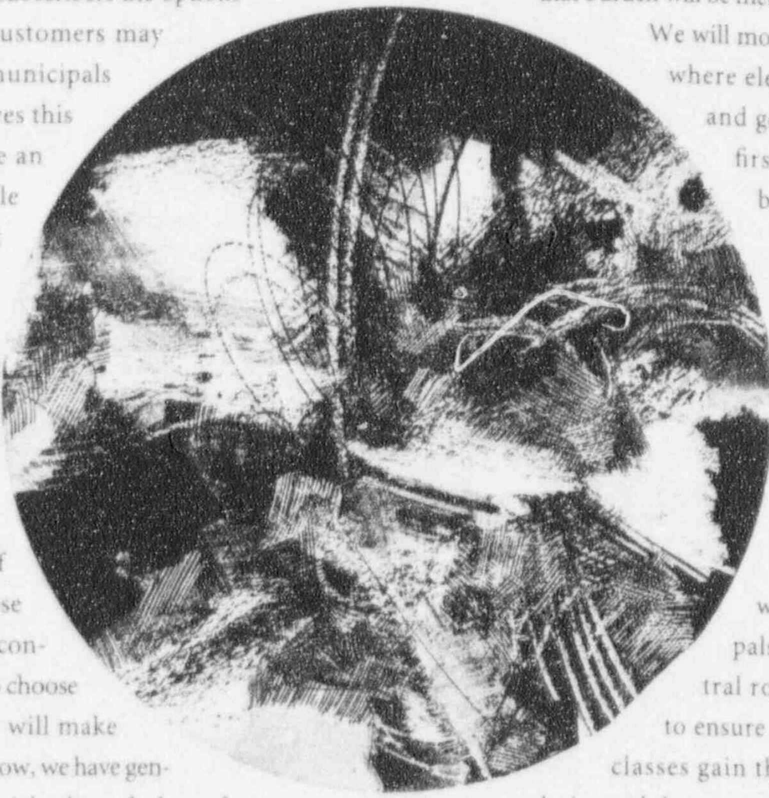
Nevertheless, these short-term exaggerated pressures should not be dismissed lightly to the extent there are long-run differences in utility costs. Customers for whom energy is an important cost will continue to look for alternatives. The same technologies and pricing options that make wholesale competition possible also can afford retail customers options that they do not currently have.

Municipal electric companies occupy an interesting niche in this process. One the one hand, they have historically viewed themselves as small publicly owned electric companies, but otherwise very much like their investor-owned brethren. They can also be viewed as cooperatives of consumers of all sizes, particularly including residential and small commercial customers.

To the extent they view themselves as agents of their customers (and it certainly seems appropriate

"In our economy, the burden of proof is upon those who would deny consumers the right to choose from whom they will make purchases."

that they should), they can become the agent to make available to small subscribers the options that very large customers may soon have. If municipals think of themselves this way, they may be an important vehicle for ensuring that any benefits from retail wheeling are shared widely with small as well as large consumers.



In our economy, the burden of proof is upon those who would deny consumers the right to choose from whom they will make purchases. Up to now, we have generally limited that right through the exclusive franchise. If retail wheeling can be efficient for a broad enough range of consumers, then it is unlikely that burden will be met.

We will move to a new world where electric companies and generators for the first time compete broadly to retain their load. This should have a salutary effect on the overall level of costs in the regulated electricity industry.

The challenge, which the municipals may play a central role in meeting, is to ensure that all customer classes gain the advantages of choice and that some are not simply left holding the bag.

MMWEC's View – *It wasn't retail wheeling, but special circumstances found the Holyoke Gas & Electric Department (HG&E) in competition with the investor-owned Holyoke Water Power Company for a 29-megawatt retail industrial load in Holyoke earlier this year.*

The competition in Holyoke resulted in lower industrial rates and a loss of revenue for both utilities, which each serve a portion of the city's industrial load. No customers changed hands, but if they had, one utility would have faced the loss of its investment in power to meet the needs of those customers, i.e. stranded investment.

Loss of revenue and stranded investment are two issues facing utilities, regulators and consumers as the debate over retail wheeling evolves. Massachusetts municipal utilities have identified many of the risks and opportunities associated with retail wheeling and other competitive issues. In anticipation of retail wheeling, the municipals are enacting strategies to participate in the regulatory process, retain existing customers and find opportunities to expand their customer base.

The *Massachusetts Energy Plan*, announced by Governor William Weld last year, outlines steps to turn our state's disadvantaged energy system – that lacks oil wells, gas fields, huge dams and coal mines – into an efficient energy system not overly reliant on any one fuel.

The plan stresses lower energy costs, which are key to continued economic stability and growth. Maintaining low costs requires diverse and multifaceted energy systems, dominated by efficient utilities and competitive markets. The state's electric utilities are particularly vital to the creation of a least-cost and environmentally sound energy future, as envisioned in the Energy Plan.

All utilities will face significant challenges in the years to come. Competition is increasing, and will continue to do so. To respond, electric utilities must begin the difficult transition from being vertically-integrated entities offering bundled services, to more streamlined and competitive organizations.

Because the loyalties of customers are no longer guaranteed by geography, all utilities must also focus on their customers' interests when moving forward with new programs and new capacity. In this pursuit, utilities will have to place more reliance on outside suppliers, making the best use of their own internal resources. Many utilities are now diversifying products and services, such as electric vehicles and electrotechnologies, or are offering completely new lines of business that complement their core energy business.

With these changes in the electric marketplace, the emphasis on environmental protection and enhancement will continue. The increasing pressure to procure "clean or green" resources will continue to be felt by municipals and investor-owned utilities.

The result of this regulatory and market pressure has been a reduction in the number of options for the procurement of new resources. New facility

Stephen J. Remen,
Commissioner of Energy Resources
Commonwealth of Massachusetts

siting issues arise, while cost uncertainties are increasingly inherent in contracts for purchased power. The state's energy plan outlines a diverse and competitive system of energy providers that rely on "least-cost" resources in terms of operation and long-term environmental and social impacts.

In the face of market changes and environmental pressures converging on the electric utility industry, demand-side management and renewable energy programs appear increasingly attractive. Both help utilities cope with the uncertainties associated with the siting, approval and cost issues that accompany traditional supply resources.

> *"Electric utilities, particularly the municipal electric systems, can and must play a major role in ensuring future price and supply stability of their systems."*

Electric utilities, particularly the municipal electric systems, can and must play a major role in ensuring future price and supply stability of their systems. Increasing reliance on least-cost and environmentally clean resources will move the state's energy system toward that goal by reducing costs to all classes of customers.

The economic benefits of this strategy are already apparent. Massachusetts boasts one of the largest concentrations of energy efficiency companies in the nation. According to the Massachusetts Energy Efficiency Council, between 1,500 and 2,000 new companies, and as many as 20,000 new jobs, have been created. The award in December of a $300 million contract to

MMWEC's View – *Municipal utilities and MMWEC are implementing part of the Massachusetts Energy Plan through their participation on the Efficiency Partnership Task Force for Municipal Utilities.*

The purpose of the task force, established under the energy plan, is to produce an action plan for expanding municipal utility demand-side management programs. The task force includes representatives of municipal utilities and government agencies, as well as public and private energy service providers.

Municipal utilities also share the fundamental energy plan goal of creating a least-cost and environmentally sound energy future that fosters economic growth. Through their membership in MMWEC they are supporting the Massachusetts Alliance for Economic Development, an organization of public and private utilities that assists businesses seeking to expand or locate in Massachusetts. Individually, several systems are leading by example in their use of electric and natural gas vehicles, which diversify the state's energy system while improving air quality.

Achieving the goals of the energy plan will benefit municipal utilities and their consumers, as well as the state as a whole.

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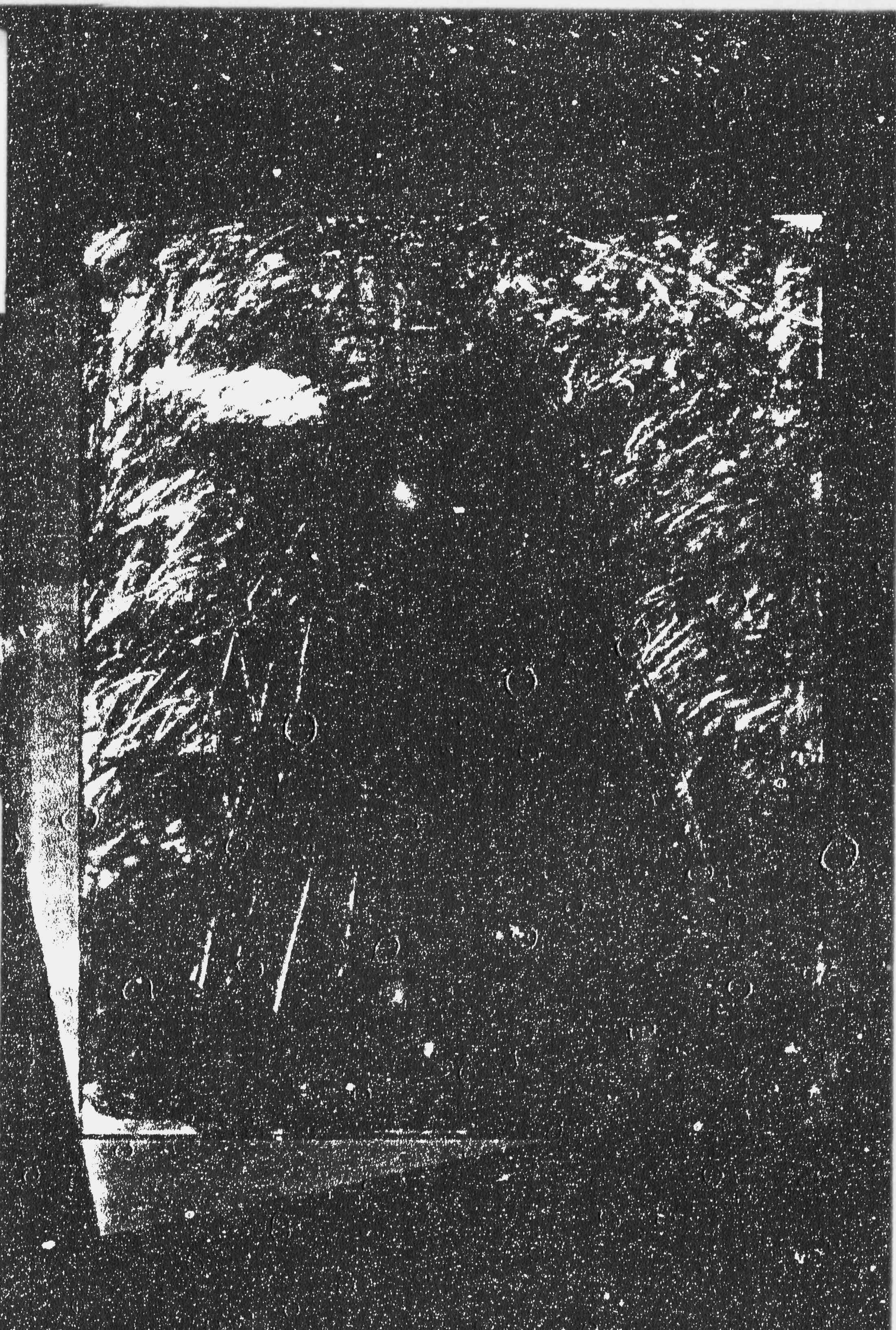


DMC Corporation of Chelsea for demand-side management services is a testimony to this fact.

The growth of new companies in the energy efficiency industry is only one economic benefit. Reducing energy costs through efficiency and lower rates increases the competitiveness of all Massachusetts employers.

The Division of Energy Resources (DOER) is working with municipal electric utilities on the design of cost-effective DSM and efficiency programs, with investor-owned electrics on regulatory and market reforms, with individual utilities on demand-side management and integrated resource plans, and with all utilities in the qualification of demand-side resources for emission reduction credits. DOER continues to work on initiatives set forth in the Massachusetts Energy Plan and seeks the full partnership of all Massachusetts electric utilities in these efforts.

Leonard S. Hyman, First Vice President
Merrill Lynch

For decades, investors in the electric industry based their requirements on a fundamental premise: the utility held a monopoly on the supply of electricity to a particular region. The utility held that monopoly because one utility, employing the largest generating equipment, could produce and sell electricity for a lower cost than a number of smaller firms each serving a small part of the market.

Investors believed that utility securities involved low risk, because of the seemingly guaranteed market for the utilities' output. The credit rating agencies, too, understood the safety of the business. They let the utilities borrow more money than would have been acceptable in other industries. After all, electricity was a necessity and the utility was the only game in town, so why worry?

By the 1970s, risks had increased. Utilities lost billions in failed nuclear projects. When electric prices rose too high, customers cut back consumption of electricity or turned to other fuels. The monopoly had limits.

By the late 1980s, several utilities filed for bankruptcy. Almost one-third of the investor-owned utilities reduced or omitted dividends. Obviously, some utilities were safer than others, but investors did not yet question the fundamental premise behind their investment strategy: that the utility held a monopoly. Nor did the credit agencies, although they lowered the ratings of many utilities, in light of the decline in financial strength caused by the numerous difficulties.

The justification for the utility's monopoly began to erode in the 1960s. Power stations had reached maximum levels of efficiency. In 1978, Congress passed the Public Utility Regulatory Policies Act, creating a new class of electricity generators that sold their output of energy to industrial concerns and to utilities. Then, electric equipment manufacturers began to produce small, easily installed, highly efficient, clean gas turbine generators with which small independent firms could produce electricity at a lower cost than that of many utilities.

Remember that the utility secured its legal monopoly because it could produce electricity at a lower cost than smaller firms. Now, many of the smaller firms could produce for less than the utility.

In 1992, Congress passed the National Energy Policy Act, easing the way for additional firms to enter the power generating business and to use the utility's transmission lines to transport the power to the customer. One year later, in late 1993, the credit rating agencies announced that they would apply new, stricter standards when rating bonds.

Could the utility keep its customers, and bring in the revenue used to pay its debt, if interlopers could undercut the utility and take away business? With the electric utility industry facing competition, the rating agencies had to adjust their views. Competition meant greater risk.

So far, most competition largely involves sales of power to electric companies (wholesale wheeling). What will happen when power suppliers attempt to sell electricity directly to the customers of the local electric utility (retail wheeling)? That would destroy the local utility's monopoly, threatening the recovery of investments made over decades to serve the local customers.

Investors have already learned, from experience with the airline, transportation, natural gas and telephone industries, that competition comes even to public service

MMWEC's View – *If power costs are an important measure of a utility's competitiveness, MMWEC participants have made great strides toward improving their competitive position in the past two years. The reduction in power costs resulting from MMWEC's refunding program, in addition to lowering rates for consumers, has given participants another competitive edge. Having lower power costs gives them more choices when responding to a particular threat or opportunity. They have more flexibility, more options for meeting their customers' needs.*

With rights to inexpensive hydroelectric preference power, and court-tested contracts for power from some of the region's most reliable and economic generating units, Massachusetts municipal utilities also have a solid and competitive long-term power supply. In addition, streamlined operations and a recovering Massachusetts economy have helped to improve the financial performance of municipal utilities.

Competition is expected to bring new challenges, but Massachusetts municipal utilities and MMWEC are continuing their successful work to prepare for a more competitive future.

industries, and when it does, ill-prepared companies suffer.

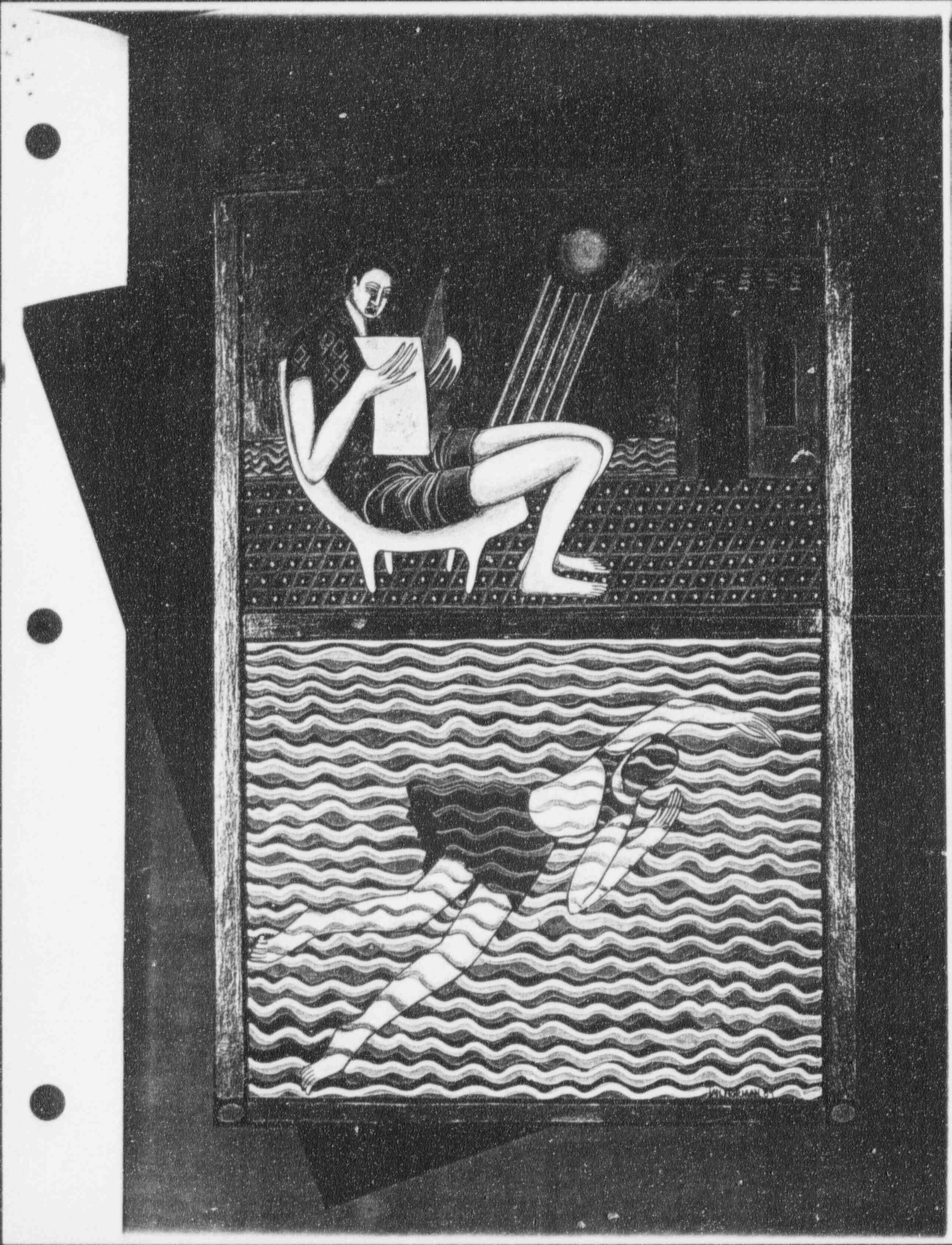
Investors, realistically, would prefer the slow introduction of competition, so that the utility could reduce its costs, recover as much on its investments as possible, and bring its financial arrangements in line with what is required in a competitive industry. Even better, they would like to think that the utility in which they have invested already has brought its costs down to those of the new competitors and has refashioned its finances for the new era. Unfortunately, few utilities have reached that point.

Realistic investors will take a hard-headed approach when defining the solid electric utility, the firm that will survive the appearance of competition, and possibly even prosper afterwards. That organization must produce power and provide all its services at the lowest possible cost. It needs an agile management and a responsive group of employees that understand that customers have choices. It will require a realistic cost-accounting system, because without such a system the utility will not know how to price the various services it will offer.

Investors will examine customer mix, the types of contracts that exist between the utility and its customers, and they will demand that the utility price its output in a way to keep those customers. During the transition period between regulated monopoly and real competition, the utility has to have policies to maximize cash flow, depreciate assets of dubious value as quickly as possible, and pay down debt to a lower level appropriate for the competitive market. And, the utility has to avoid taking on obligations that will turn into burdens with the onset of competition.

Few utilities now have all the requisites to succeed in a new marketplace. Investors know that. They hope that the utility will have time to evolve with the market. They want to see signs that the utility is not simply keeping up with - but is instead moving ahead of - the pace of change.

"Few utilities now have all the requisites to succeed in a new marketplace. Investors know that."



David W. Penn
Director of Policy Analysis
American Public Power Association

"...all that will count in the end is how electric utilities deal with their retail customers."

Some might think it strange to deal with the importance of customer service programs for distribution utilities at a time when most of the attention in the U.S. has been on wholesale competition and power supply matters. Let me explain why all that will really count in the end is how electric utilities deal with their retail customers, before covering general and specific services that customers have a right to expect from their utilities.

The high-voltage transmission of electricity from generating sites to load centers will continue to be a natural monopoly. In contrast, it has long been recognized that there is room for a great deal more competition in the production of electricity. However, generation competition developed slowly in the U.S. despite congressional passage of the Public Utilities Regulatory Policy Act in 1978.

As the 1990s approached, different regions of the country, and even smaller market areas, found themselves with wide variations in the amount and cost of delivering generating capacity. One region might be in need of capacity and high priced, while another nearby had extra capacity and much lower prices. If there were fewer barriers and more competition in generation supply, capacity-to-load relationship would equalize across regions, and so would prices.

Addressing this, Congress passed the Energy Policy Act of 1992. Its two key provisions 1) encouraged the development of independent generation suppliers, and 2) gave the federal government clear authority to order the transmission-owning utilities to provide access to the transmission highways that allow electricity to move from areas of surplus to areas of need.

These are momentous changes in the industry. They are already causing dramatic restructuring of the industry, of its competitors, and of its regulation. These changes have absorbed Congress and regulators and are capturing the media headlines.

But what do they mean for distribution utilities and their customers? Certainly, they mean more generation options and lower prices for wholesale power, and, hence, lower ultimate prices.

But the genie of competition is out of the lamp and over time these changes also mean that prices for wholesale power will tend to equalize for distribution utilities. Then, all of the attention and pressure will be on utilities to supply electricity competitively to ultimate customers. Distributors will have to concentrate on customer service programs that fulfill customers' expectations. Regarding this, it is important to remember that municipal distributors will be competing for franchises and existing and new industrial loads. Customers will decide who will supply them on the basis of what is offered and at what price.

In general, a customer can expect distribution utility service that is:

• reliable and capable of meeting variable power and voltage requirements;

• equally or lower priced when compared with alternatives;

• forward-looking and planning in anticipation of customer needs;

• coordinated with other community needs, such as economic development and housing programs;

• open to participation and scrutiny, making customers part of the decision-making process.

In short, customers can expect electricity service that is responsive to the individual customer's needs, delivered by a utility that is a good local citizen. Massachusetts and other municipal electric utilities are ideally suited to meet these general service expectations. They have a history of reliable, responsive service and lower prices over the long run. Most important, they are an integral part of their local communities.

Specific customer service programs, which vary with local needs, might include such things as customer advisory panels, a customer information center, more convenient office hours, alternative payment plans, or cold-weather heating funds. In addition, new technology is greatly expanding the number and variety of demand-management programs, which can be tailored to meet local customer needs.

The mix of customer service programs appropriate to meet the expectations of distribution utility customers will provide the competitive edge necessary to continue in our new world of competition.

MMWEC's View – *Consumer-owned utilities, like the Massachusetts municipal systems, are widely known to be more customer- and service-oriented than their investor-owned counterparts. Being owned and operated by the people they serve is part of the reason for this. The consumer-owners of municipal utilities have a direct say in how the utility operates, through the ballot box and at regularly scheduled public meetings.*

Municipal utilities are valuable assets to the communities they serve, providing a broad range of utility and other services to schools, libraries, senior citizens and other town departments, depending on local needs. They are close to their customers, and can respond to their needs promptly.

In planning to enhance their service, municipal utilities recognize that customers' needs and expectations are changing. New service technology, voltage-sensitive equipment and environmental concerns are among the reasons municipal systems are working to expand the scope and role of customer service programs.

If there is competition to retain existing customers and obtain new ones, the quality of service provided by community-based municipal utilities will give them an edge.

MMWEC Directors and Officers

Thomas R. Josie, *Director*

Other directors and officers, pictured in the management letter at the beginning of this report, include Richard E. Slattery, Director and Chairman of the Board; Edla A. Bloom, Director and President; and David A. Sjosten, Secretary and General Manager.

John Larch, *Director*

Gilbert McCarthy, *Director*

David I. Sweetland, *Director*

H. Bradford White, *Director*

Nicholas J. Scobbo, *General Counsel*

John M. Wesolowski, *Treasurer*

James E. Fuller, *Assistant Treasurer*

Massachusetts Municipal Wholesale Electric Company

1993 Financial Statements

MMWEC

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Independent Auditors' Report

The Board of Directors

Massachusetts Municipal Wholesale Electric Company:

We have audited the accompanying statements of financial position of Massachusetts Municipal Wholesale Electric Company (a Massachusetts public corporation) as of December 31, 1993, 1992 and 1991 and the related statements of operations and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Massachusetts Municipal Wholesale Electric Company as of December 31, 1993, 1992 and 1991, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

KPMG Peat Marwick

March 11, 1994

MMWEC

Statements of Financial Position

Years Ended December 31, 1993, 1992 and 1991

(In Thousands)

	1993	1992	1991
Assets			
Electric Plant			
In Service (Note 4)	$ 1,233,845	$ 1,231,359	$ 1,231,621
Accumulated Depreciation	(243,440)	(201,172)	(157,897)
	990,405	1,030,187	1,073,724
Nuclear Fuel - net of amortization	19,553	24,626	32,226
Total Electric Plant	1,009,958	1,054,813	1,105,950
Special Funds (Notes 2, 3 and 7)	191,099	196,259	256,187
Current Assets			
Cash and Temporary Investments (Note 7)	1,013	3,619	1,828
Accounts Receivable	9,361	6,163	5,723
Unbilled Revenues	7,813	8,491	8,718
Inventories at Cost	14,846	15,261	19,663
Prepaid Expenses	7,636	6,652	5,643
Total Current Assets	40,669	40,186	41,575
Total Special Funds and Current Assets	231,768	236,445	297,762
Deferred Charges			
Amounts Recoverable (Payable) Under Terms of the Power Sales Agreements (Note 2)	189,808	132,312	35,005
Unamortized Debt Discount and Expenses	39,340	40,272	35,322
Other	7,649	5,921	6,242
	236,797	178,505	76,569
	$ 1,478,523	$ 1,469,763	$ 1,480,281
Liabilities			
Long-Term Debt			
Bonds Payable (Note 3)	$ 1,374,605	$ 1,376,700	$ 1,380,955
Current Liabilities			
Current Maturities of Long-Term Debt (Note 3)	33,175	28,110	19,765
Notes Payable (Note 3)	64	113	–
Accounts Payable	8,332	11,081	15,682
Accrued Expenses	17,561	11,167	9,376
Member and Participant Advances and Reserves	44,786	42,592	54,503
	103,918	93,063	99,326
Commitments and Contingencies (Notes 4 and 6)			
	$ 1,478,523	$ 1,469,763	$ 1,480,281

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

MMWEC

Statements of Operations

Years Ended December 31, 1993, 1992 and 1991

(In Thousands)

	1993	1992	1991
Revenues (Note 2)	$ 248,630	$ 275,041	$ 276,487
Interest Income	11,083	13,435	18,925
Total Revenues and Interest Income	$ 259,713	$ 288,476	$ 295,412
Operating and Service Expenses:			
Fuel Used in Electric Generation	$ 20,062	$ 23,831	$ 28,917
Purchased Power	74,134	78,925	78,789
Other Operating	29,451	32,533	32,147
Maintenance	10,470	11,873	11,393
Depreciation	44,187	44,101	44,016
Taxes Other Than Income	6,076	8,225	7,312
	184,380	199,488	202,574
Interest Expense:			
Interest Charges	89,742	114,459	135,445
Interest Charged to Projects During Construction (Note 2)	(169)	(466)	(967)
	89,573	113,993	134,478
Total Operating Costs and Interest Expense	273,953	313,481	337,052
Cost of Advance Refunding (Note 3)	43,857	73,180	-
Gain on Cancelled Units - Net (Note 4)	(601)	(671)	(1,069)
Gain on Retirement of Debt	--	(207)	(704)
	43,256	72,302	(1,773)
Decrease (Increase) in Amounts Recoverable Under Terms of the Power Sales Agreements (Note 2)	(57,496)	(97,307)	(39,867)
	$ 259,713	$ 288,476	$ 295,412

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

MMWEC
Statements of Cash Flows

Years Ended December 31, 1993, 1992 and 1991
(In Thousands)

	1993	1992	1991
Cash flows from operating activities:			
Total Revenues and Interest Income	$ 259,713	$ 288,476	$ 295,412
Total Costs and Expenses, net	(317,209)	(385,783)	(335,279)
Adjustments to arrive at net cash provided by operating activities:			
Depreciation and decommissioning	45,112	44,978	44,655
Amortization	24,805	34,795	13,602
Gain on land taken by eminent domain	–	–	(292)
Change in current assets and liabilities:			
Accounts Receivable	(3,198)	(440)	13
Unbilled Revenues	678	227	347
Inventories	415	4,402	(2,481)
Prepaid Expenses	(984)	(1,009)	173
Accounts Payable	(2,749)	(4,601)	5,972
Accrued Expenses and Other	4,720	(361)	(508)
Member and Participant Advances and Reserves	2,194	(11,911)	11,518
Net cash provided (used) by operating activities	13,497	(31,227)	33,132
Cash flows from investing activities:			
Construction expenditures and purchases of nuclear fuel	(10,312)	(4,943)	(5,608)
Interest Charged to Projects During Construction	(169)	(466)	(967)
Net reduction in Special Funds	5,160	59,928	66
Decommissioning Trust refunds (payments), net	(1,259)	1,297	(997)
Proceeds from property disposal and other	620	426	729
Net cash provided (used) for investing activities	(5,960)	56,242	(6,777)
Cash flows from financing activities:			
Proceeds from sale of bonds	444,290	748,295	–
Payment for bond issue costs	(13,064)	(27,427)	–
Payments for principal of Long-Term Debt	(29,165)	(27,880)	(26,335)
Payment for defeasance of bonds	(412,155)	(716,325)	–
Change in Notes Payable	(49)	113	(1)
Net cash used for financing activities	(10,143)	(23,224)	(26,336)
Net increase (decrease) in cash and temporary investments	(2,606)	1,791	19
Cash and temporary investments at beginning of year	3,619	1,828	1,809
Cash and temporary investments at end of year	$ 1,013	$ 3,619	$ 1,828
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 86,035	$ 111,464	$ 132,966

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

Notes to Financial Statements

(1) Massachusetts Municipal Wholesale Electric Company (MMWEC)

MMWEC is a political subdivision of the Commonwealth of Massachusetts, authorized to issue revenue bonds secured by revenues derived from Power Sales Agreements (PSAs) (see Note 6) with its members and other electric systems to finance the construction and ownership of electric power facilities.A Massachusetts city or town having a municipal electric department, authorized by majority vote of the city or town, may become a member by applying for admission to MMWEC and agreeing to comply with the terms and conditions of membership as the MMWEC By-Laws may require.As of December 31, 1993, twenty-eight Massachusetts municipalities were members.

MMWEC obtains power supply capacity by acquiring interests in various generating units and the operation of its own electric generating facilities (Projects).See Note 4 for a discussion of MMWEC's electric generation facilities and commitments relating thereto.In addition, MMWEC contracts for power for resale to its members and other utilities.

(2) Significant Accounting Policies

MMWEC presents its financial statements in accordance with generally accepted accounting principles as promulgated by the Financial Accounting Standards Board and the Governmental Accounting Standards Board.

Interest Charged to Projects During Construction

MMWEC capitalizes interest as an element of the cost of (1) electric plant while under construction, including an appropriate testing period and (2) nuclear fuel in process.A corresponding amount is reflected as a reduction of interest expense.The amount of interest capitalized is based on the cost of debt, including amortization of debt discount and expenses, related to each Project, net of investment gains and losses and interest income derived from unexpended Project funds.

Nuclear Fuel

Nuclear fuel includes MMWEC's ownership interest of fuel in use, in stock and in process for Millstone Unit 3 and Seabrook Station.Fuel in use is reflected net of accumulated amortization of $50.8, $40.0 and $27.7 million through December 31, 1993, 1992 and 1991, respectively.The cost of nuclear fuel is amortized to Fuel Used in Electric Generation based on the relationship of energy produced in the current period to total expected energy production for fuel in the reactor.A provision for fuel disposal costs is included in Fuel Used in Electric Generation based upon disposal contracts with the Department of Energy (DOE).In addition, Fuel Used in Electric Generation includes the annual assessment, under the Energy Policy Act of 1992, for the costs of decontamination and decommissioning of uranium enrichment plants operated by the DOE.Billings from the DOE will occur over the next 14 years.At December 31, 1993, MMWEC's share of Millstone Unit 3 and Seabrook Station unbilled assessments was $481,000 and $816,000, respectively.The amounts are included in other deferred charges and accrued expenses.

Special Funds

Proceeds from the sales of revenue bonds for Projects are deposited with Trustees to be invested until they are required for costs of acquisition and construction or debt service payments.The Special Funds, other than certain working funds, are restricted as to their use by the General Bond Resolution, which also prescribes investment thereof.Investments are limited to direct obligations of, or other obligations the principal of and interest on which are unconditionally guaranteed by the United States, Federal government agency securities, new housing authority bonds issued by public agencies or municipalities, direct and general obligations of certain states or political subdivisions, bank time deposits evidenced by certificates of deposits issued by banks, and repurchase agreements with primary dealers secured by certain securities.Certain Special Funds are more restricted as to which of the aforementioned investments can be purchased.Special Funds include amounts held in trust under Power Purchase Agreements, working capital arrangements and agency contracts.These trusteed funds are invested in securities as outlined within the General Bond Resolution, and in repurchase agreements secured by certain securities at banks where MMWEC has established accounts, although the working capital arrangement and agency contracts are not governed by the General Bond Resolution.(See Note 7.)The composition of Special Funds is as follows:

Fund	1993	1992	1991
		(In Thousands)	
Construction Fund for deposit of bond proceeds to be used for costs of acquisition and construction	$ —	$ 517	$ 5,893
Bond Fund Interest, Principal and Retirement Account to pay principal and interest on bonds	19,573	15,370	14,844
Bond Fund Reserve Account set at the maximum annual interest obligation to make up any deficiencies in the Bond Fund Interest Principal and Retirement Account	88,166	102,243	146,664
Reserve and Contingency Fund to make up deficiencies in the Bond Fund and pay for renewals and extraordinary costs	17,140	18,364	20,078
Revenue Fund to receive revenues and disburse them to other funds	47,461	47,784	58,191
Working Capital Funds to maintain funds to cover operating expenses	18,759	11,981	10,517
Total Special Funds	$191,099	$196,259	$256,187

Notes to Financial Statements

(2) **Significant Accounting Policies (continued)**

Cash and Temporary Investments

Certain cash and temporary investment amounts are used for power purchases and working capital requirements of MMWEC. These funds are not governed by the General Bond Resolution. In addition to the investment securities delineated in the General Bond Resolution, MMWEC purchases Canadian currency for cash and forward settlement and invests in repurchase agreements with banks where MMWEC has established accounts. (See Note 7.)

Inventories

Fuel oil and spare parts inventory are recorded and accounted for by the average cost method. At December 31, 1993, 1992 and 1991, fuel oil inventory was valued at $4.2, $3.4 and $4.3 million, and spare parts inventory amounted to $10.6, $11.9 and $15.4 million, respectively.

Revenues and Unbilled Revenues

Revenues include electric sales for resale provided from MMWEC's operating units and power purchases and billings for administrative and general services provided to MMWEC's Service Participants. These and additional details of revenues are as follows:

Revenues	1993	1992	1991
		(In Thousands)	
Electric sales for resale	$ 243,817	$ 270,455	$ 271,578
Service	2,813	2,586	2,617
PSNH Settlement	2,000	2,000	2,000
Gain on land taken by eminent domain	–	–	292
Revenues	$ 248,630	$ 275,041	$ 276,487

MMWEC bills its members for costs incurred in providing services and purchased power obtained on their behalf under terms of the Service Agreement and Power Purchase Agreements. Service revenues are recorded as the expenses are incurred. Amounts which are not yet billed are included in Unbilled Revenues on the Statements of Financial Position.

The difference between amounts billed currently under the terms of the PSAs and total expenses recorded in the Statement of Operations is charged or credited to Amounts Recoverable Under Terms of the PSAs.

Amounts Recoverable Under Terms of the Power Sales Agreements

Billings to Project Participants are designed to recover costs in accordance with the PSAs. The billings are therefore structured on a Project-by-Project basis to provide for debt service, operating funds and reserve requirements. Expenses are reflected in the Statements of Operations in accordance with generally accepted accounting principles. The timing difference between amounts billed and expensed is charged or credited to Amounts Recoverable Under Terms of the PSAs. Amounts will be recovered through future billings or an expense will be recognized to offset credit balances. The principal differences include depreciation, fuel amortization, costs associated with cancelled Projects, cost of advance refunding, certain interest, reserves and other costs. The reduction of Amounts Recoverable Under Terms of the PSAs for Projects with billings in excess of cost is primarily due to the billing of interest costs for Projects under construction through June 30, 1990. An increase in Amounts Recoverable Under Terms of the PSAs is primarily caused by recognition of depreciation expense in excess of bond principal payments related to a Project and the cost of advanced refunding. Individual Projects with a cumulative deferral of costs total $201.4, $164.9 and $155.4 million and Projects with cumulative billings in excess of costs total $11.6, $32.6 and $120.4 million at December 31, 1993, 1992 and 1991, respectively. These amounts have been netted in the Statements of Financial Position.

Depreciation

Electric plant in service is depreciated using the straight-line method. The aggregate annual provisions for depreciation for 1993, 1992 and 1991 averaged 4% of the original cost of depreciable property.

(3) **Debt**

Power Supply System Revenue Bonds

To finance construction of ownership interests in electric generating facilities under its General Bond Resolution, MMWEC issued Power Supply System Revenue Bonds (Bonds). The Bonds are secured under the General Bond Resolution by a pledge of the revenues derived by MMWEC under the terms of the PSAs and from the ownership and operation of the Projects in its power supply system. Pursuant to the PSAs each Project Participant is obligated to pay its share of the actual costs relating to the generating units planned, under construction or in operation. The Project Participants' obligations are not contingent upon the completion or operational status of the units.

MMWEC financings, other than obligations maturing within one year, require Massachusetts Department of Public Utilities' (DPU) authorization. In November 1993, MMWEC received authorization to issue up to $1,165.8 million of refunding bonds and subsequently used $334.78 million of said amount to issue the 1994 Series A and B bonds in February 1994.

In 1993 and 1992, MMWEC issued $444.3 and $748.3 million of refunding bonds, respectively. The proceeds of 1993 Series bonds, when combined with $14.5 million from the Bond Fund Reserve Account and Bond Fund Principal Account were utilized to defease $412.1 million of the 1976 Series A bonds and portions of the 1978 Series A, 1979 Series A and 1987 Series A bonds. The proceeds of 1992 Series bonds, when combined with $49.1 million from the Bond Fund Reserve Account, Construction Fund and Bond Fund Principal Account were utilized to defease $716.3 million of high interest bonds comprised of the 1980 through 1982 Series bonds and portions of the 1984 Series A, 1985 Series B and 1987 Series B bonds. The proceeds from the refunding bonds and the available funds have been deposited in an irrevocable escrow account and used to purchase direct obligations of the United States Government in an

(3) **Debt (continued)**

Power Supply System Revenue Bonds (continued)

amount sufficient to pay the debt service requirements of the refunded bonds through the redemption dates.The cost of the 1993 and 1992 advance refundings equalled $43.9 and $73.2 million, net of $2.8 and $7.9 million of expenses, respectively.MMWEC in effect reduced its aggregate debt service payments by $146.6 and $693.4 million over the next 27 and 28 years and obtained an economic gain (difference between the present values of the old and new debt service payments) of $65.5 and $288.2 million for the 1993 and 1992 refundings, respectively.

The fair values of MMWEC's long-term debt instruments are estimated based on the quoted market prices for the same or similar issues of the same remaining maturities.As of December 31, 1993, the carrying amount and estimated fair value of MMWEC's long-term debt is $1,374.6 and $1,436.1 million, respectively.Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument.These estimates are subjective in nature, involve uncertainties and judgment, and cannot be determined with precision.Changes in assumptions could significantly affect the estimates.

Bonds Payable consist of Serial and Term Bonds and are comprised of the following issues, which are generally subject to optional redemption approximately ten years after the issue date, at 103% of the principal amount, descending periodically thereafter to 100%.

Issue	Net Interest Cost	December 31, 1993	1992 (In Thousands)	1991
1976 Series A	7.2%	$ –	$ 56,005	$ 57,140
1977 Series A	6.4%	144,240	147,815	154,430
1977 Series B	6.1%	74,325	75,910	77,525
1978 Series A	6.8%	1,085	60,045	61,010
1979 Series A	7.0%	–	118,125	122,400
1980 Series A	10.2%	–	–	77,835
1981 Series A	12.3%	–	–	98,365
1981 Series B	13.4%	–	–	81,415
1982 Series A	13.4%	–	–	61,150
1982 Series B	10.2%	–	–	126,045
1984 Series A	11.0%	800	1,515	93,380
1985 Series B	13.5%	525	825	52,620
1987 Series A	8.9%	10,730	195,815	198,005
1987 Series B	11.8%	–	540	139,400
1992 Series A	7.0%	104,910	104,910	–
1992 Series B	7.0%	322,665	326,335	–
1992 Series C	6.9%	61,070	61,070	–
1992 Series D	6.3%	104,690	105,805	–
1992 Series E	6.0%	140,050	149,040	–
1992 Series F	5.3%	–	1,055	–
1993 Series A	5.3%	441,255	–	–
1993 Series B	5.9%	1,435	–	–
Bonds Payable		1,407,780	1,404,810	1,400,720
Less: Current Maturities		(33,175)	(28,110)	(19,765)
Total Long-Term Debt		$ 1,374,605	$ 1,376,700	$ 1,380,955

The aggregate annual principal payments due on the Bonds in the next five years are as follows:1994 – $33,175,000; 1995 – $34,565,000; 1996 – $35,980,000; 1997 – $37,735,000; and 1998 – $39,705,000.

Net Revenue Available for Debt Service

In accordance with the provisions of MMWEC's General Bond Resolution, MMWEC covenants that it shall fix, revise and collect rates, tolls, rents and other fees and charges, sufficient to produce revenues to pay all operating and maintenance expenses and principal of, premium, if any, and the interest on Bonds and to pay all other obligations against its revenue.Revenues, which include applicable interest earnings from investments, are required to equal 1.10 times the annual debt service for each contract year ending June 30, after deduction of certain operating and maintenance expenses and exclusive of depreciation.For the contract years ended June 30, 1993, 1992, 1991 and prior years, MMWEC met the General Bond Resolution debt service coverage requirements for the applicable MMWEC Projects.

	Contract Year Ended June 30, 1993	1992 (In Thousands)	1991
Debt Service Coverage:			
Revenues	$ 168,531	$ 195,952	$ 181,887
Other Billings	661	713	713
Reserve and Contingency Fund Billings	12,444	14,542	13,757
Total	181,636	211,207	196,357
Less: Operating & Maintenance Expenses	(44,747)	(51,251)	(45,024)
Available Revenues Net of Expenses	$ 136,889	$ 159,956	$ 151,333
Debt Service Requirement	$ 124,444	$ 145,414	$ 137,575
Coverage (110% Required)	110%	110%	110%

(3) Debt (continued)

Notes Payable

MMWEC maintains a $7.2 million revolving line of credit to finance temporarily certain power purchases made by MMWEC for resale under power purchase contracts.The balances outstanding were $64,000, $113,000 and $0 as of December 31, 1993, 1992 and 1991, respectively, with a maximum outstanding balance of $641,000, $556,000 and $0 during 1993, 1992 and 1991, respectively.Interest charged on borrowings under the line of credit is at the bank's prime rate.In addition, a commitment fee of one half of 1% per annum is charged on the unused portion of the line based on the average daily principal amount of the loan outstanding.

(4) Electric Generation Facilities and Financing

MMWEC's power supply capacity includes interests in the Stony Brook Peaking and Intermediate units which it operates.MMWEC is a nonoperating joint owner in the W.F. Wyman No. 4, Millstone Unit 3 and Seabrook Station units.Electric Plant In Service also includes MMWEC's Service Operations which totalled $2.3, $2.3 and $2.2 million in 1993, 1992 and 1991, respectively.

Projects	Facility and MMWEC Share of Capability (MW)		Amounts as of December 31, 1993	1992	1991
				(In Thousands)	
Peaking Project	Stony Brook	170.0	$ 56,330	$ 56,289	$ 56,247
Intermediate Project	Stony Brook	311.3	150,322	147,973	146,529
Wyman Project	W.F. Wyman No. 4	22.7	7,357	7,394	7,354
Nuclear Project No.3	Millstone Unit 3	36.8	128,651	128,372	128,371
Nuclear Mix No. 1	Millstone Unit 3	18.4	50,816	50,677	50,676
Nuclear Mix No. 1	Seabrook Station	1.9	8,575	8,579	8,604
Nuclear Project No.4	Seabrook Station	49.8	258,545	258,665	259,346
Nuclear Project No.5	Seabrook Station	12.6	70,764	70,794	70,966
Project No. 6	Seabrook Station	69.0	500,186	500,352	501,295
			$ 1,231,546	$ 1,229,095	$ 1,229,383

In January 1988, Public Service of New Hampshire (PSNH), then the lead owner of Seabrook Station, filed for protection from its creditors under Chapter 11 of the Federal Bankruptcy Code.In June 1992, in accordance with a court-approved plan of reorganization, Northeast Utilities (NU) acquired PSNH and placed Seabrook Station in a separate single asset subsidiary corporation.

In May 1991, New Hampshire Electric Cooperative (NHEC), a 2% Seabrook Station joint owner, filed for protection from its creditors under Chapter 11 of the U.S. Bankruptcy Code.NHEC continues to make all of its Seabrook payments.A joint plan of reorganization has been approved by the court and NHEC expects a final court decree in 1994.

In February 1991, EUA Power Corporation, a 12% joint owner of Seabrook Station, filed for protection from its creditors under Chapter 11 of the U.S. Bankruptcy Code.Two Seabrook Station joint owners have funded in part, the EUA Power Corporation Seabrook obligations.The Bondholders Committee filed a plan of reorganization which was approved by the Bankruptcy Court.EUA Power Corporation changed its name to Great Bay Power Corporation, has received regulatory approval of certain aspects of the plan and anticipates final approval in 1994.The Bondholders Committee plan assumes the Seabrook Joint Ownership Agreement (JOA).

In June 1988, MMWEC's Board of Directors adopted a strategic plan of action relating to its Seabrook Station joint ownership interests.MMWEC and PSNH subsequently entered into a Memorandum of Understanding whereby PSNH paid MMWEC's capital costs up to $30 million, MMWEC maintained its full ownership in Seabrook Station and agreed to a Comprehensive Settlement Agreement which was approved by the bankruptcy court.The Agreement provided for amendments to the Seabrook JOA, notices of default being rescinded, certain covenants not to sue, PSNH to pay MMWEC $2 million per year for eight years upon commercial operation of Seabrook, joint termination of the Sellback Agreement between MMWEC and PSNH and certain other considerations.

MMWEC's investment in Seabrook Station represents a substantial portion of its plant investment and financing.Seabrook Station experienced persistent cost increases and schedule delays, including the cancellation of Unit 2.The Seabrook Station joint owners have authorized the sale or transfer of all salvageable components and equipment from the cancelled Unit 2.MMWEC's net costs, including interest expenses, in Seabrook Unit 2 of $126.4, $127.0 and $127.6 million as of December 31, 1993, 1992 and 1991, respectively, have been deferred and are being recovered under the terms of the PSAs.

In 1981, the Boston Edison Company cancelled Pilgrim Unit 2, which is included in MMWEC's Nuclear Mix No. 1.MMWEC's net costs, including interest expense associated with the Unit, which aggregates $61.2 million were deferred and are being recovered under the terms of the PSAs.

(5) Benefit Plans

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

The Pension Benefit Obligation was computed as part of an actuarial valuation performed as of January 1, 1993.Significant actuarial assumptions used in the valuation include a weighted-average discount rate of 8.0% a year compounded annually, and projected salary increases of 5.5% a year compounded annually.The Pension Benefit Obligation for both plans is as follows:

(5) **Benefit Plans (continued)**

	Amounts as of January 1,		
	1993	1992	1991
		(In Thousands)	
Retirees currently receiving benefits and terminated employees not yet receiving benefits	$ 137	$ 123	$ 105
Current Employees:			
Vested	1,423	1,172	900
Non-vested	1,447	1,239	1,010
Total Pension Benefit Obligation	3,007	2,534	2,015
·t assets available for benefits, at market	2,395	1,859	1,260
Unfunded Pension Benefit Obligation	$ 612	$ 675	$ 755

Net assets available for benefits, at market as a percentage of the Pension Benefit Obligation were 79.6%, 73.3%, and 62.5% as of January 1, 1993, 1992 and 1991, respectively.The unfunded Pension Benefit Obligation as a percentage of covered payroll was 11.4%, 12.94% and 15.67% for the years ended January 1, 1993, 1992 and 1991, respectively.

MMWEC makes annual contributions to the pension plans equal to the amounts recorded as pension expense, which were $489,000, $467,000, and $414,000 for the years ended December 31, 1993, 1992 and 1991, respectively.Contributions as a percentage of MMWEC's covered payroll were 8.9%, 8.3% and 7.9% for the years ended December 31, 1993, 1992 and 1991, respectively.The union plan uses the aggregate actuarial cost method and the non-union plan uses the frozen initial liability actuarial cost method in determining pension expense.In addition to the actuarial assumptions outlined above, the assumed long-term rate of return used in determining pension expense was 9.5%.Pension costs applicable to prior years' service are amortized over thirty years.Ten-year historical trend and other information which is required to be disclosed in accordance with Governmental Accounting Standards Statement No. 5 is not considered material and therefore is not presented.

MMWEC contributes to an employee savings plan administered by an insurance company.All full-time employees meeting the service requirements are eligible to participate in this defined contribution plan.Under the provisions of the plan, MMWEC's contributions vest immediately.MMWEC contributed $105,000, $94,000 and $84,000 while the employees contributed $170,000, $165,000 and $144,000 during the years ended December 31, 1993, 1992 and 1991, respectively.

(6) **Commitments and Contingencies**

Power Purchases

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

Power Sales Agreements

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

In 1985, the Vermont Department of Public Service (VDPS) brought an action against MMWEC in a Vermont Superior Court challenging the validity of the Project No. 6 PSAs between MMWEC and the Vermont Project No. 6 Participants.In 1986, the Superior Court ruled that these Project No. 6 PSAs were valid.The plaintiffs appealed this ruling to the Vermont Supreme Court which ruled in 1988, among other things that the Project No. 6 PSAs with the Vermont utilities were void since inception.In January 1989, the Vermont Supreme Court denied an MMWEC motion for a rehearing and MMWEC subsequently filed a writ of certiorari with the United States Supreme Court which was denied.

The Vermont Supreme Court decision, together with VDPS actions, and a Vermont Public Service Board order resulted in all the Vermont Project No. 6 Participants ceasing to make their PSA payments to MMWEC.The default by the Vermont Participants and Eastern Maine Electric Cooperative (EMEC) brought about the reallocation of the Project No. 6 Project Capability in accordance with the step-up provisions of the PSA and precipitated various lawsuits discussed below.

Inasmuch as the Stony Brook Intermediate Project has approximately 8.2% of Project Capability under PSAs with Vermont entities, which PSAs are virtually identical to the Project No. 6 PSA, the Vermont Supreme Court decision on the Project No. 6 PSA could have equal application to the Stony Brook Intermediate PSAs.The Vermont Legislature enacted legislation seeking to validate the Stony Brook Intermediate PSA in light of the Vermont Supreme Court decision.MMWEC sought a declaration in a Vermont Superior Court on the validity of the Stony Brook Intermediate PSA, as well as the legality of the curative legislation.In August 1992, the court declared the Stony Brook Intermediate PSA valid and the Vermont Supreme Court upheld that decision in February 1994.

The Vermont Supreme Court decision declaring the Project No. 6 Vermont Participants' contracts void since inception caused certain Massachusetts Project No. 6 Participants to file complaints in Massachusetts Superior Court relating to the validity of their

(6) Commitments and Contingencies (continued)

Power Sales Agreements (continued)

PSAs and the imposed step–up therein.As alleged in the complaints, a condition precedent to the validity of all the Project No. 6 PSAs is 100% participation, and if the Vermont Participants' contracts were void since inception, this condition precedent has not been met.The complaints alleged that the step–up in Project No. 6 billings, as a result of the default by the Vermont PSAs, failed to have 100% participation and MMWEC's use of other Project No. 6 funds to cover the shortfall in receipts constituted a breach of the PSAs.

In 1989, MMWEC filed an original action in the Supreme Judicial Court for Suffolk County against two Massachusetts Project No. 6 Participants.The Supreme Judicial Court for Suffolk County combined this case with the other Project No. 6 Participant cases pending in the Superior Court and granted two preliminary injunctions, ordering the nonpaying Participants to pay their obligations.After the case was remanded to it in 1990, the Superior Court stayed any further proceedings and ruled that the nonpayment of the Vermont Participants constituted a default within the meaning of the governing documents and that this default triggered the step–up and other related actions required by the PSAs.On appeal, the Supreme Judicial Court for the Commonwealth (SJC) opined that "the Project 6 PSAs executed by the defendants are valid and that the step–up provisions therein have been properly invoked."In October 1991, judgment entered for MMWEC in the Superior Court.A writ of certiorari with the United States Supreme Court seeking to overturn the SJC opinion was rejected.

In 1992, the Superior Court amended the 1991 judgment stating that the only issue remaining in this case was the Sellback Damages Claims of three Participants against MMWEC.By stipulation of all parties to the case, all rights of appeal with respect to the 1991 judgment entered in the Superior Court and the 1992 order amending that judgment and all issues decided therein were waived.Therefore, all issues regarding rescission of the Project No. 6 PSA raised in this case have been decided in favor of MMWEC.

In 1992, the Superior Court granted MMWEC's summary judgment motion on the Sellback Damages Claims.Two Participants appealed this order granting Summary Judgment to the Massachusetts Appeals Court where this matter is currently under advisement.A successful appeal by the Participants could put the case to trial.

In 1989, Washington Electric Cooperative, Inc. (WEC) filed an action seeking restitution for amounts paid MMWEC under the Project No. 6 PSA.MMWEC filed a counterclaim against certain directors, managers and attorneys for misrepresentation.Morrisville subsequently sued MMWEC and Stowe, Vermont in Vermont Superior Court.All of the other Vermont entities formerly in Project No. 6 intervened in this action and sought restitution of the total $6.2 million paid to MMWEC under the Project No. 6 PSA.

In 1991, seventeen Massachusetts municipal light departments, which are Participants in MMWEC's Project No. 6, and MMWEC separately filed actions against the Vermont utilities which were Project No. 6 Participants and their respective managers, consultants and lawyers.These separate actions seek damages resulting from the imposition of the step–up in Project No. 6 in 1992. The Federal Court denied MMWEC's motion to consolidate these cases with the WEC case.In 1993, the Federal Magistrate granted all of the defendants' motions to dismiss and/or for summary judgment.MMWEC filed objections to the Magistrate's recommendation with the Federal District Court judge which ruled that MMWEC/the Massachusetts Participants cannot recover damages from the Vermont utilities but may be able to collect damages from the attorneys who issued opinions.Between the WEC case and the State Court actions, the Vermont entities are seeking $6.2 million, plus interest, in restitution.Discovery in the state and federal court actions is underway.

Eastern Maine Electric Cooperative (EMEC), a Participant in MMWEC's Project No. 6, defaulted on its PSA payment in 1987 and subsequently filed for protection under Chapter 11 of the Federal Bankruptcy Code.In 1988, the bankruptcy court denied EMEC's attempted rejection of its PSA with MMWEC and subsequently ruled that EMEC's plan of reorganization was non confirmable.Subsequently, EMEC, the Massachusetts Participants, the Project No. 6 Participants Committee and MMWEC entered into a settlement of all claims, wherein EMEC is to pay the Project No. 6 Participants $15 million.The consensual plan was filed in January 1994 and approved by the bankruptcy court in March 1994.

Based on bond counsels' opinions regarding the validity of the Power Sales Agreements and general counsel representations regarding the litigation, discussions with such counsel, and other considerations, management believes that the ultimate resolution of the actions described above will not have a material, adverse effect on the financial position of MMWEC.MMWEC continues to enforce the provisions of the Power Sales Agreements to assure that adequate revenues are collected to meet debt service payments on its bonds in accordance with the terms of the General Bond Resolution.

Other Issues

MMWEC, as a joint owner of the Millstone Unit 3 and Seabrook Station nuclear units, is required to set aside funds for their eventual decommissioning.MMWEC's policy is to fund these reserve requirements over the licensed life of the units through monthly billings to MMWEC Participants in the unit.MMWEC's share of the total estimated Millstone's Unit 3 and Seabrook Station's projected reserve requirement is $18 million and $42 million, of which $2.7 and $1.9 million has been funded, respectively, as of December 31, 1993.The amounts are included in other deferred charges and accrued expenses.

In August 1988, an amendment to the Price–Anderson Act was enacted, calling for a fifteen year extension of the nuclear liability indemnification process.The Act now provides approximately $9.4 billion for public liability claims from a single incident at a nuclear facility.The $200 million primary layer of insurance for the liability has been purchased in the commercial market.Secondary coverage of $8.8 billion is to be provided through a $75.5 million per incident assessment of each of the currently licensed nuclear units in the United States.The maximum assessment is $10 million per incident per unit in any year.If the sum of the liability claims and costs from an incident exceed the maximum amount of financial protection, each reactor owner is subject to an additional $3.8 million assessment.The maximum assessment is subject to adjustment for inflation every five years.MMWEC's interest in Millstone Unit 3 and Seabrook Station could result in a maximum assessment of $3.6 and $8.8 million, respectively.

(6) **Commitments and Contingencies (continued)**

Other Issues (continued)

Insurance has been purchased from Nuclear Electric Insurance Limited (NEIL) to cover the cost of repair, replacement, or decontamination or premature decommissioning of utility property resulting from insured occurrences at Millstone Unit 3 and Seabrook Station.MMWEC is subject to a $1 million assessment, for its participation in Millstone Unit 3 and Seabrook Station for excess property damage, decontamination and decommissioning, as well as retroactive assessments if losses exceed the financial resources available to NEIL.

MMWEC is not currently covered under gradual pollution liability insurance related to MMWEC's Stony Brook power plant.Management is not aware of any material claims made during 1993 or outstanding as of December 31, 1993.

Additional information regarding commitments and contingencies relative to MMWEC's debt and involvement in nuclear projects is discussed in Note 3 – Debt and Note 4 -- Electric Generation Facilities and Financing.

7) **Investments and Deposits**

All bank deposits, which amounted to $404,627 at December 31, 1993, are maintained at one financial institution.The Federal Deposit Insurance Corporation currently insures up to $100,000 per depositor.MMWEC's uninsured deposits ranged from zero to $2.8 million during 1993 due to seasonal cash flows, the timing of daily cash receipts and favorable earnings offered on these demand deposits.Investments are stated at cost adjusted for accretion (amortization) of the discount (premium).MMWEC's normal practice is to hold its investments until maturity.At December 31, 1993, all securities underlying repurchase agreements, and all other investments, were held in MMWEC's name by independent custodians consisting of the Construction Fund Trustees, Bond Fund Trustee or MMWEC's depository bank.Investments, representing the Special Funds and Cash and Temporary Investments, as well as certain additional amounts disbursed but available for investment, and accrued interest, are presented below:

Type of Investment	1993 Carrying Amount	1993 Market Value	1992 Carrying Amount	1992 Market Value	1991 Carrying Amount	1991 Market Value
			(Thousands)			
Repurchase Agreements	$ 2,735	$ 2,893	$ 2,219	$ 2,289	$ 15,888	$ 16,308
Other Investments:						
U.S. Treasury bills	15	15	65	65	–	–
U.S. Treasury notes	97,283	101,090	84,681	87,257	37,013	38,163
U.S. Agency bonds	16,314	16,958	18,446	19,240	56,614	57,569
U.S. Agency discount notes	76,824	76,832	96,758	96,762	149,045	149,101
Investment in Mutual Funds	42	42	–	–	–	–
Total Other Investments	190,478	194,937	199,950	203,324	242,672	244,833
Total Investments	$ 193,213	$ 197,830	$ 202,169	$ 205,613	$ 258,560	$ 261,141

Temporary investments, made up of funds available from amounts for which the expense has been recognized but not cleared by the bank, approximate $.8, $2.2 and $.5 million in 1993, 1992 and 1991, respectively, and are included in the total investments noted above.

Due to seasonal cash flows during 1993, 1992 and 1991, MMWEC, from time to time, invested in repurchase agreements with its depository bank that were collateralized by securities in MMWEC's name held by the depository bank.MMWEC's practice is to monitor the market value of the underlying securities to ensure that the market value equals or exceeds the amount invested.Management estimated market values of the securities based on independent quoted market prices.

MMWEC

Independent Auditors' Report on Supplementary Information

The Board of Directors

Massachusetts Municipal Wholesale Electric Company:

We have audited and reported separately herein on the financial statements of Massachusetts Municipal Wholesale Electric Company as of and for the years ended December 31, 1993, 1992 and 1991.

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

KPMG Peat Marwick

March 11, 1994

MMWEC

Project Statements of Financial Position

Schedule I

December 31, 1993 (In Thousands)

	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTER-MEDIATE	WYMAN	HYDRO QUEBEC PHASE II	TOTAL
ASSETS											
Electric Plant											
In Service	$ 2,299	$ 59,391	$ 128,651	$ 258,545	$ 70,764	$ 500,186	$ 56,330	$ 150,322	$ 7,357	$ –	$ 1,233,845
Accumulated Depreciation	(1,902)	(12,627)	(29,633)	(31,392)	(8,611)	(61,242)	(24,851)	(69,959)	(3,223)	–	(243,440)
	397	46,764	99,018	227,153	62,153	438,944	31,479	80,363	4,134	–	990,405
Nuclear Fuel net of amortization	–	1,382	2,299	5,340	1,407	9,125	–	–	–	–	19,553
Total Electric Plant	397	48,146	101,317	232,493	63,560	448,069	31,479	80,363	4,134	–	1,009,958
Special Funds											
Bond Fund											
Interest, Principal and Retirement Account	–	2,181	1,591	2,163	778	7,086	1,663	3,988	123	–	19,573
Reserve Account	–	10,039	12,931	16,073	4,542	34,765	2,603	6,623	590	–	88,166
Reserve and Contingency Fund	–	3,432	2,160	3,271	994	4,642	856	1,503	282	–	17,140
Revenue Fund	–	1,786	3,084	4,678	1,302	9,530	8,255	17,701	1,125	–	47,461
Working Capital Funds	18,771	–	–	–	–	–	–	–	–	(12)	18,759
	18,771	17,438	19,766	26,185	7,616	56,023	13,377	29,815	2,120	(12)	191,099
Current Assets											
Cash and Temporary Investments	1,015	–	–	1	–	1	–	–	–	(4)	1,013
Accounts Receivable	5,779	250	253	891	192	1,534	89	223	23	127	9,361
Unbilled Revenues	7,813	–	–	–	–	–	–	–	–	–	7,813
Inventories at cost	–	68	–	1,803	456	2,496	1,511	8,186	326	–	14,846
Advances to (from) Projects	632	(35)	(57)	(32)	(20)	(127)	(51)	(303)	(7)	–	–
Prepaid Expenses	380	718	1,286	1,940	491	2,687	3	102	29	–	7,636
Total Current Assets	15,619	1,001	1,482	4,603	1,119	6,591	1,552	8,208	371	123	40,669
Total Special Funds and Current Assets	34,390	18,439	21,248	30,788	8,733	62,614	14,929	38,023	2,491	111	231,768
Deferred Charges											
Amounts Recoverable (Payable) Under Terms of the Power Sales Agreements	–	79,877	88,754	(11,207)	3,121	8,512	892	20,304	(51)	(394)	189,808
Unamortized Debt Discount and Expenses	–	2,827	5,283	7,090	3,036	17,124	645	3,236	99	–	39,340
Other	70	1,157	2,197	1,313	335	1,849	8	94	45	581	7,649
	70	83,861	96,234	(2,804)	6,492	27,485	1,545	23,634	93	187	236,797
	$ 34,857	$ 150,446	$ 218,799	$ 260,477	$ 78,787	$ 538,168	$ 47,953	$ 142,020	$ 6,718	$ 298	$ 1,478,523
LIABILITIES											
Long-Term Debt											
Bonds Payable	$ –	$ 144,015	$ 212,325	$ 249,300	$ 75,610	$ 515,570	$ 43,005	$ 128,665	$ 6,115	$ –	$ 1,374,605
Current Liabilities											
Current Maturities of Long-Term Debt	–	4,045	3,175	4,465	1,460	10,560	2,805	6,420	245	–	33,175
Notes Payable	64	–	–	–	–	–	–	–	–	–	64
Accounts Payable	4,154	78	72	1,120	284	1,551	17	1,022	32	2	8,332
Accrued Expenses	5,684	1,501	2,815	2,371	601	3,289	12	1,231	57	–	17,561
Member and Participant Advances and Reserves	24,955	807	412	3,221	832	7,198	2,114	4,682	269	296	44,786
	34,857	6,431	6,474	11,177	3,177	22,598	4,948	13,355	603	298	103,918
	$ 34,857	$ 150,446	$ 218,799	$ 260,477	$ 78,787	$ 538,168	$ 47,953	$ 142,020	$ 6,718	$ 298	$ 1,478,523

and Reserves	24,955	807	412	[illegible]	832	7,198	2,114	4,682	269	296	44,786
	34,857	6,431	6,474	[illegible]	3,177	22,598	4,948	13,355	603	298	103,918
	$ 34,857	$ 150,446	$ 218,799	$ [illegible]	$ 78,787	$ 538,168	$ 47,953	$ 142,020	$ 6,718	$ 298	$ 1,478,523

MMWEC

Project Statements of Financial Position

Schedule II

December 31, 1993 *(In Thousands)*

	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTER-MEDIATE	WYMAN	HYDRO QUEBEC PHASE II	TOTAL
Revenues	$ 75,837	$ 16,330	$ 22,843	$ 28,809	$ 8,246	$ 56,102	$ 7,379	$ 30,896	$ 1,573	$ 615	$ 248,630
Interest Income	566	1,011	1,411	1,710	508	3,434	612	1,582	96	153	11,083
Total Revenues and Interest Income	$ 76,403	$ 17,341	$ 24,254	$ 30,519	$ 8,754	$ 59,536	$ 7,991	$ 32,478	$ 1,669	$ 768	$ 259,713
Operating and Service Expenses:											
Fuel Used in Electric Generation	$ –	$ 660	$ 1,142	$ 3,348	$ 893	$ 6,068	$ 464	$ 7,077	$ 410	$ –	$ 20,062
Purchased Power	73,519	–	–	–	–	–	–	–	–	615	74,134
Other Operating	2,742	2,201	3,911	5,186	1,364	8,015	1,237	4,435	360	–	29,451
Maintenance	36	1,183	2,277	1,095	277	1,517	251	3,713	121	–	10,470
Depreciation	79	1,896	4,019	9,242	2,529	17,874	2,257	6,064	227	–	44,187
Taxes Other Than Income	8	476	859	1,195	302	1,655	391	1,078	112	–	6,076
	76,384	6,416	12,208	20,066	5,365	35,129	4,600	22,367	1,230	615	184,380
Interest Expense:											
Interest Charges	19	9,342	13,481	16,311	4,841	34,862	2,709	7,751	426	–	89,742
Interest Charged to Projects During Construction	–	(13)	(30)	(43)	(12)	(71)	–	–	–	–	(169)
	19	9,329	13,451	16,268	4,829	34,791	2,709	7,751	426	–	89,573
Total Operating Costs and Interest Expense	76,403	15,745	25,659	36,334	10,194	69,920	7,309	30,118	1,656	615	273,953
Cost of Advance Refunding	–	2,196	20,316	12,241	3,437	–	–	5,667	–	–	43,857
Loss on Cancelled Units – net	–	(9)	–	(224)	(57)	(311)	–	–	–	–	(601)
	–	2,187	20,316	12,017	3,380	(311)	–	5,667	–	–	43,256
Decrease (Increase) in Amounts Recoverable Under Terms of the Power Sales Agreements	–	(591)	(21,721)	(17,832)	(4,820)	(10,073)	682	(3,307)	13	153	(57,496)
	$ 76,403	$ 17,341	$ 24,254	$ 30,519	$ 8,754	$ 59,536	$ 7,991	$ 32,478	$ 1,669	$ 768	$ 259,713

MMWEC

Project Statements of Financial Position

Schedule III

December 31, 1993 (In Thousands)

	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTER-MEDIATE	WYMAN	QUEBEC PHASE II	TOTAL
Cash flows from operating activities:											
Total Revenues and Interest Income	$ 76,403	$ 17,341	$ 24,254	$ 30,519	$ 8,754	$ 59,536	$ 7,991	$ 32,478	$ 1,669	$ 768	$ 259,713
Total Costs and Expenses, net	(76,403)	(17,932)	(45,975)	(48,351)	(13,574)	(69,609)	(7,309)	(35,785)	(1,656)	(615)	(317,209)
Adjustments to arrive at net cash provided by operating activities:											
Depreciation and decommissioning	79	2,045	4,299	9,468	2,586	18,187	2,240	5,981	227	–	45,112
Amortization	–	1,932	4,143	5,670	1,847	6,824	129	4,242	18	–	24,805
Change in current assets and liabilities:											
Accounts Receivable	(520)	(203)	(167)	(778)	(163)	(1,293)	(89)	76	(23)	(38)	(3,198)
Unbilled Revenues	678	–	–	–	–	–	–	–	–	–	678
Inventories	–	–	–	(7)	(2)	(10)	(479)	930	(17)	–	415
Prepaid Expenses	(104)	16	57	(349)	(88)	(483)	–	(88)	55	–	(984)
Accounts Payable	(1,280)	8	7	(352)	(83)	(657)	(28)	(272)	(57)	(35)	(2,749)
Accrued Expenses and Other	2,123	(6)	(72)	955	240	1,284	(225)	462	(41)	–	4,720
Member and Participant Advances and Reserves	3,204	(844)	(1,934)	1,800	415	2,718	(581)	(2,375)	(94)	(115)	2,194
Net cash provided by (used for) operating activities	4,180	2,337	(15,388)	(1,425)	(68)	16,497	1,649	5,649	81	(35)	13,497
Cash flows from investing activities:											
Construction expenditures and purchases of nuclear fuel	(91)	(762)	(1,363)	(2,075)	(525)	(2,875)	(41)	(2,571)	(9)	–	(10,312)
Interest charged to Projects during Construction	–	(13)	(30)	(43)	(12)	(71)	–	–	–	–	(169)
Net increase (decrease) in Special Funds	(6,782)	[illegible]	4,911	415	260	(3,499)	1,087	5,387	163	4	5,160
Decommissioning Trust payments	–	(204)	(388)	(253)	(64)	(350)	–	–	–	–	(1,259)
Other	166	54	106	28	7	38	–	231	–	–	620
Net cash provided by (used for) investing activities	(6,707)	2,289	3,236	(1,928)	(334)	(6,757)	1,046	3,037	154	4	(5,960)
Cash flows from financing activities:											
Proceeds from sale of bonds	–	55,885	131,155	101,365	41,880	–	–	114,005	–	–	444,290
Payment for bond issue costs	–	(1,761)	(3,828)	(3,061)	(1,248)	–	–	(3,166)	–	–	(13,064)
Payments for principal of Long-Term Debt	–	(2,765)	(2,220)	(4,290)	(1,265)	(9,740)	(2,695)	(5,955)	(235)	–	(29,165)
Payment for defeasance of bonds	–	(56,005)	(112,955)	(90,660)	(38,965)	–	–	(113,570)	–	–	(412,155)
Change in Notes Payable	(49)	–	–	–	–	–	–	–	–	–	(49)
Net cash provided by (used for) financing activities	(49)	(4,646)	12,152	3,354	402	(9,740)	(2,695)	(8,686)	(235)	–	(10,143)
Net increase (decrease) in cash and temporary investments	(2,576)	–	–	1	–	–	–	–	–	(31)	(2,606)
Cash and temporary investments at beginning of year	3,591	–	–	–	–	1	–	–	–	27	3,619
Cash and temporary investments at end of year	$ 1,015	$ –	$ –	$ 1	$ –	$ 1	$ –	$ –	$ –	$ (4)	$ 1,013
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 19	$ 8,991	$ 13,019	$ 15,699	$ 4,606	$ 33,589	$ 2,580	$ 7,124	$ 408	$ –	$ 86,035

Cash and temporary investments at beginning of year	3,591	–	–	–	–	1	–	–	–	27	3,649
Cash and temporary investments at end of year	$ 1,015	$ –	$ –	$ 1	$ –	$ 1	$ –	$ –	$ –	$ (4)	$ 1,013
Cash paid during the year for interest											
(Net of amount capitalized as shown above)	$ 19	$ 8,991	$ 13,019	$ 15,699	$ 4,606	$ 33,589	$ 2,580	$ 7,124	$ 408	$ –	$ 86,035

New refunding bond issue

MMWEC completed the sale of $334.78 million in tax-exempt bonds on March 15. Proceeds of the bond issue, which carries a true interest cost of 5.17 percent, have been used to refund previously issued, higher-interest bonds.

The bond sale includes $115.78 million in 1994 Series A bonds, which were used to refund $100.6 million of the outstanding 1992 Series B bonds. The 1992 Series B bonds refunded were selected by lot from the $144 million of 6.75 percent 1992 Series B term bonds due in 2017. These bonds, which were advance refunded, will be called on July 1, 2002 at a premium of 102 percent.

In addition, $219 million in 1994 Series B bonds were used to refund all of the outstanding $218.5 million of 1977 Series A and B bonds, which were called on March 17 at a premium of 102 percent.

The 1994 Series A and B bonds, rated AAA, are insured by the Municipal Bond Investors Assurance Corp. and the AMBAC Indemnity Corp.

The refunded bonds were issued to finance MMWEC's ownership in the Seabrook Station, Millstone Unit No. 3 and Wyman Unit No. 4 power plants. Lower debt service resulting from the refunding has reduced power costs for MMWEC participants by $53 million over the next 23 years, or about $2.4 million a year.

The 1994 bond issue is MMWEC's fifth refunding bond issue since April 1992, bringing the total amount of refunding bonds issued to more than $1.5 billion. The savings from the refunding program have reached more than $850 million over the life of the bonds, or about $35 million a year.

Moody's upgrades MMWEC rating

Moody's Investors Service, siting a number of positive developments for MMWEC and its participants, upgraded MMWEC's credit rating from Baa1 to A on Jan. 18. It is significant to note that the upgrade came at a time when the rating agencies were setting higher standards for electric utilities due to risks associated with increasing competition in the industry.

Among Moody's reasons for the upgrade were lower municipal utility rates, the resolution of disputes over the validity of MMWEC power contracts, and a better relationship between MMWEC and its municipal utility participants. The lower rates are primarily the result of MMWEC's debt refunding program.

Improvements in the regional economy and above-average operation of Seabrook Station were also cited as reasons for the upgrade. The Moody's report states that "substantially lower and more competitive" municipal utility rates have "added a degree of financial flexibility to both MMWEC and its participants." On Jan. 20, Fitch Investors Service and Standard & Poor's Corp. reaffirmed their MMWEC ratings of A- and BBB+, respectively.

Litigation update

The final challenge to the validity of MMWEC's Seabrook power sales contracts was resolved on Jan. 21 when the Rhode Island Supreme Court denied the petition of the Pascoag (R.I.) Fire District to have its contract with MMWEC voided.

In denying Pascoag's petition, the court upheld a January 1993 decision of the Rhode Island Public Utilities Commission, which had denied Pascoag's earlier request for a declaration that its contract with MMWEC was void. The contract at issue, signed in 1979, involves Pascoag's purchase from MMWEC of 1,229 kilowatts of Seabrook power.

The time period for appeal of the Rhode Island Supreme Court decision has expired and a related federal court case has been terminated, ending Pascoag's challenge to the validity of MMWEC's Project No. 6 Seabrook contract.

In other litigation, the U.S. Bankruptcy Court for the District of Maine has confirmed a consensual plan of reorganization for the Eastern Maine Electric Cooperative (EMEC), which filed for Chapter 11 bankruptcy protection in August 1987 after defaulting on its Project No. 6 contract with MMWEC.

Under the plan, the 21 participants in MMWEC's Project No. 6 are expected to receive a total of $15.2 million from EMEC. The effectiveness of the reorganization plan and EMEC's emergence from bankruptcy are both contingent on full payment of the $15.2 million to the MMWEC participants. The Project No. 6 participants assumed EMEC's share of project capability and costs following EMEC's default.

The claims of MMWEC and its project participants against EMEC were settled during the nearly seven years of litigation and settlement discussions that led to the court's March 4 approval of the reorganization plan.

In one of the final lawsuits stemming from the 1988 decision voiding the Seabrook power contracts between MMWEC and six Vermont utilities, the Lamoille (Vermont) Superior Court has found MMWEC liable for payments made by four of the utilities before the contracts were voided. The April 15 decision also denies MMWEC's counterclaims for damages against the utilities.

The four utilities seeking restitution in the Lamoille Superior Court paid MMWEC approximately $3.4 million before the contracts were voided. All six Vermont utilities paid MMWEC a total of about $6.2 million before the contracts were voided. MMWEC retains the right to appeal the Superior Court decision after the Vermont utilities file an accounting of amounts they believe are due from MMWEC with the court.

In a separate federal court case, MMWEC has filed counterclaims and claims seeking damages from the attorneys who represented the Vermont utilities and provided MMWEC with false assurances that, among other things, the utilities had the authority to enter into the contracts.

1993 energy use is up 2.3 percent

Electric energy use among MMWEC member utilities in 1993 increased 2.3 percent over 1992, reversing a trend of relatively level use over the past several years.

The 1993 increase is being attributed to unusually hot summer weather, as well as an improving Massachusetts economy.

Bitterly cold winter weather resulted in an increase in energy use among MMWEC members of 9.6 percent during January 1994, compared to January 1993. Through March 1994, members' energy use was up 3.6 percent compared to the same period last year.

MMWEC

First Quarter Report

For the months ended March 31, 1994

Massachusetts Municipal Wholesale Electric Company
Moody Street, Ludlow, MA 01056
(413) 589-0141

Massachusetts Municipal Wholesale Electric Company

Statements of Financial Position

March 31, 1994 and 1993
(Unaudited)
(Dollars In Thousands)

	March 31, 1994	March 31, 1993
ASSETS		
Electric Plant		
In Service	$1,234,192	$1,231,223
Accumulated Depreciation	(254,484)	(211,665)
	979,708	1,019,558
Nuclear Fuel-Net of Amortization	17,362	22,017
Total Electric Plant	997,070	1,041,575
Special Funds	218,112	235,236
Current Assets		
Cash and Temporary Investments	1,439	5,182
Accounts Receivable	8,335	6,317
Unbilled Revenues	7,354	7,451
Inventories at Cost	12,119	15,144
Prepaid Expenses	8,246	7,512
	37,493	41,606
Total Special Funds and Current Assets	255,605	276,842
Deferred Charges		
Amounts Recoverable Under Terms of the Power Sales Agreements	218,013	136,675
Unamortized Debt Discount and Expenses	38,637	39,475
Other	8,249	6,231
	264,899	182,381
	$1,517,574	$1,500,798
LIABILITIES		
Long-Term Debt		
Bonds	$1,392,890	$1,376,700
Current Liabilities		
Current Maturities of Long-Term Debt	30,500	28,110
Notes Payable	–	132
Accounts Payable	8,491	9,885
Accrued Expenses	36,324	37,072
Member and Participant Advances and Reserves	49,369	48,899
	124,684	124,098
	$1,517,574	$1,500,798

Massachusetts Municipal Wholesale Electric Company

Statements of Operations

March 31, 1994 and 1993
(Unaudited)
(Dollars In Thousands)

	Three Months Ended March 31, 1994	Three Months Ended March 31, 1993	Twelve Months Ended March 31, 1994	Twelve Months Ended March 31, 1993
Revenues	$60,992	$61,469	$248,154	$268,743
Interest Income	2,825	2,628	11,281	12,547
Total Revenues and Interest Income	$63,817	$64,097	$259,435	$281,290
Operating and Service Expenses:				
Fuel Used in Electric Generation	$ 6,873	$ 4,357	$ 22,579	$ 21,307
Purchased Power	17,187	18,703	72,618	76,820
Other Operating	7,162	7,052	29,561	31,980
Maintenance	1,880	1,077	11,274	11,780
Depreciation	11,089	11,036	44,240	44,111
Taxes Other Than Income	1,533	2,028	5,580	8,169
	45,724	44,253	185,852	194,167
Interest Expense:				
Interest Charges	21,083	24,290	86,536	105,204
Interest Charged to Projects During Construction	(2)	(39)	(132)	(287)
	21,081	24,251	86,404	104,917
Total Operating Costs and Interest Expense	66,805	68,504	272,256	299,084
Cost of Advance Refunding	25,223	–	69,080	73,180
Gain on Cancelled Units – Net	(4)	(44)	(561)	(296)
Gain on Retirement of Debt	(1)	–	(1)	–
	25,218	(44)	68,518	72,884
(Increase) Decrease in Amounts Recoverable Under Terms of the Power Sales Agreements	(28,206)	(4,363)	(81,339)	(90,678)
	$63,817	$64,097	$259,435	$281,290

These unaudited financial statements should be read in conjunction with the Massachusetts Municipal Wholesale Electric Company (MMWEC) 1993 Annual Financial Statements.

The 1993 MMWEC Annual Report was produced by the Corporate Communications / Public Affairs Office of the Massachusetts Municipal Wholesale Electric Company. Copies of this report and supplemental financial information can be obtained, free of charge, by writing to the Corporate Communications / Public Affairs Office, Massachusetts Municipal Wholesale Electric Company, P.O. Box 426, Ludlow, MA 01056. All requests for information about MMWEC should be directed to this office

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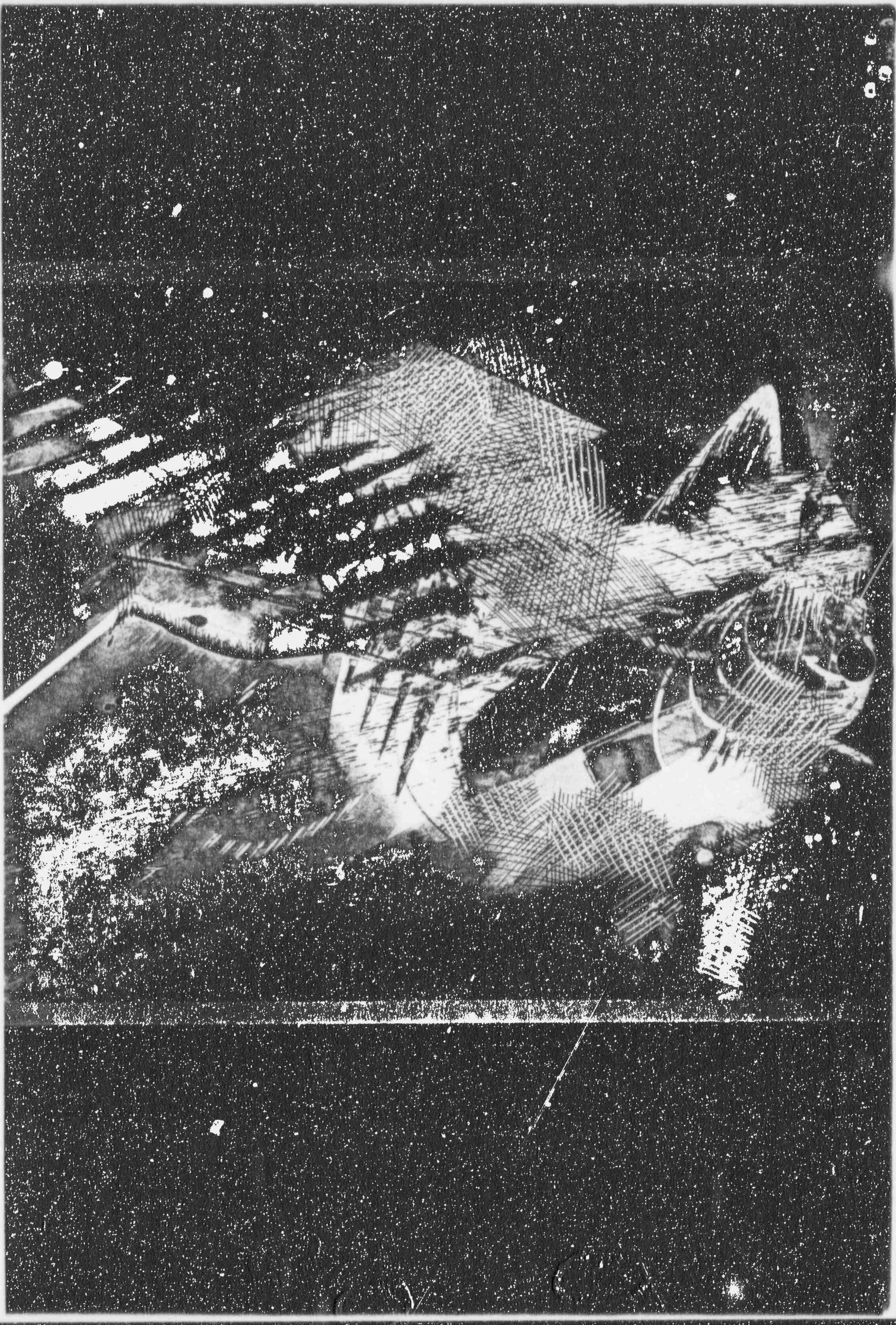
1994
Quarterly
Reports



gathering and maintaining the data needed, and completing and ... is estimated to average 24.25 hours (REA Form 12a-1) per response, including the time for reviewing instructions, searching existing data sources ... ving the collection of information. Send comments regarding this ... n estimate or any other aspect of this collection of information including suggestions for reducing this burden, to Department ... iculture, Clearance Officer, OIRM, AG Box 7630, Washington, D ... 250; and to the Office of Management and Budget, Paperwork Reduction Project (OMB #0572-0017), Washington, DC 20503. OMB FORM NO. 0572-0017, Expires 12/31/94.

This data will be used by REA to review your financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

A2-1-10

USDA-REA

OPERATING REPORT - FINANCIAL

BORROWER DESIGNATION
Vermont 12 Hampshire

BORROWER NAME AND ADDRESS
Vermont Electric G & T Cooperative, Inc.
School Street
Johnson, Vermont 05656

INSTRUCTIONS - *Submit an original and two copies to REA. Round all amounts to nearest dollar. For detailed instructions, see REA Bulletin 1717B-3*

PERIOD ENDED
December 31, 1993

REA USE ONLY

CERTIFICATION

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, REA, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES. DOL coverage cancelled 8-24-86; we have been unable to obtain replacement coverage.

Linda Reeve
SIGNATURE OF OFFICE MANAGER OR ACCOUNTANT
3/16/94
DATE

SIGNATURE OF MANAGER
3/16/94
DATE

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	14 572 271	14 570 000	14 563 421	1 213 743
2. Income From Leased Property (Net)				
3. Other Operating Revenue and Income	32 131	19 384	17 700	2 608
4. Total Oper. Revenues & Patronage Capital *(1 thru 3)*	14 604 402	14 589 384	14 581 121	1 216 351
5. Operating Expense - Production - Excluding Fuel	1 117 671	1 172 844	1 010 910	151 785
6. Operating Expense - Production - Fuel	332 224	330 442	385 049	35 537
7. Operating Expense - Other Power Supply	3 552 325	3 614 417	3 688 208	284 435
8. Operating Expense - Transmission	658 314	620 107	571 506	40 263
9. Operating Expense - Distribution				
10. Operating Expense - Customer Accounts	1 103	1 014	1 200	85
11. Operating Expense - Customer Service & Information				
12. Operating Expense - Sales				
13. Operating Expense - Administrative & General	697 888	640 811	377 741	67 369
14. Total Operation Expense *(5 thru 13)*	6 359 525	6 379 635	6 034 614	579 474
15. Maintenance Expense - Production	34 807	39 224	36 000	2 276
16. Maintenance Expense - Transmission				
17. Maintenance Expense - Distribution				
18. Maintenance Expense - General Plant				
19. Total Maintenance Expense *(15 thru 18)*	34 807	39 224	[illegible] 000	2 276
20. Depreciation and Amortization Expense	1 698 257	1 709 087	1 756 644	142 578
21. Taxes	445 218	329 408	461 633	(13 597)
22. Interest on Long-Term Debt	3 279 837	3 024 741	3 270 734	231 706
23. Interest Charged to Construction - Credit	( )	( )	( )	(
24. Other Interest Expense	2 854 021	3 142 503	3 068 816	279 778
25. Other Deductions	52 415			
26. Total Cost of Electric Service *(14 + 19 thru 25)*	14 724 080	14 624 598	14 628 441	1 222 215
27. Operating Margins *(4 less 26)*	(119 678)	(35 214)	(47 320)	(5 864)
28. Interest Income	119 673	35 214	47 320	5 864
29. Allowance For Funds Used During Construction				
30. Income (Loss) from Equity Investments				
31. Other Nonoperating Income (Net)	5			
32. Generation & Transmission Capital Credits				
33. Other Capital Credits and Patronage Dividends				
34. Extraordinary Items				
35. Net Patronage Capital or Margins *(27 thru 34)*	-0-	-0-	-0-	-0-

ITEM	Mills/kWh *(Optional Use by Borrower)*		
36. Electric Energy Revenue per kWh Sold			
37. Total Operation & Maintenance Expense Per kWh Sold			
38. Total Cost of Electric Service per kWh Sold			
39. Purchase Power Cost Per kWh Sold			

USDA-REA

OPERATING REPORT - FINANCIAL

BORROWER DESIGNATION: Vermont 12 Hampshire

PERIOD ENDED: December 31, 1993

REA USE ONLY

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	59 302 664	32. Memberships	30
2. Construction Work in Progress		33. Patronage Capital	
3. Total Utility Plant (1 + 2)	*59 302 664	a. Assigned and Assignable	(326 475)
4. Accum. Provision for Depreciation and Amort.	**11 022 048	b. Retired This Year	
5. Net Utility Plant (3 - 4)	***48 280 616	c. Retired Prior Years	
6. Non-Utility Property (Net)		d. Net Patronage Capital	(326 475)
7. Investments in Subsidiary Companies		34. Operating Margins - Prior Years	
8. Invest. in Assoc. Org. - Patronage Capital		35. Operating Margins - Current Year	
9. Invest. in Assoc. Org. - Other - General Funds	19 177	36. Non-Operating Margins	
10. Invest. in Assoc. Org. - Other - Nongeneral Funds		37. Other Margins and Equities	20
11. Investments in Economic Development Projects		38. Total Margins & Equities (32 + 33d thru 37)	(326 425)
12. Other Investments	152 464	39. Long-Term Debt - REA (Net)	12 790 112
13. Special Funds		(Payments-Unapplied $)	
14. Total Other Property and Investments (6 thru 13)	171 641	40. Long-Term Debt - REA - Econ. Devel. (Net)	
15. Cash - General Funds	500	41. Long-Term Debt - FFB - REA Guaranteed	10 919 776
16. Cash - Construction Funds - Trustee		42. Long-Term Debt - Other - REA Guaranteed	16 789 272
17. Special Deposits		43. Long-Term Debt - Other (Net)	
18. Temporary Investments		44. Total Long-Term Debt (39 thru 43)	40 499 160
19. Notes Receivable (Net)		45. Obligations Under Capital Leases - Noncurrent	
20. Accounts Receivable - Sales of Energy (Net)	44 591 449	46. Accumulated Operating Provisions	
21. Accounts Receivable - Other (Net)	50 286	47. Total Other Noncurrent Liabilities (45 + 46)	
22. Fuel Stock		48. Notes Payable	5 268 179
23. Materials and Supplies - Other		49. Accounts Payable	11 339 071
24. Prepayments	108 360	50. Taxes Accrued	70 853
25. Other Current and Accrued Assets		51. Interest Accrued	4 839 093
26. Total Current and Accrued Assets (15 thru 25)	44 750 595	52. Other Current and Accrued Liabilities	****36 972 639
27. Unamortized Debt Discount & Extraor. Prop. Losses	2 281 446	53. Total Current & Accrued Liabilities (48 thru 52)	58 489 836
28. Regulatory Assets		54. Deferred Credits	90 750
29. Other Deferred Debits	#3 269 022	55. Accumulated Deferred Income Taxes	
30. Accumulated Deferred Income Taxes		56. Total Liabilities and Other Credits	
31. Total Assets and Other Debits (5+14+26 thru 30)	98 753 320	(38 + 44 + 47 + 53 thru 55)	98 753 320

SECTION C. NOTES TO FINANCIAL STATEMENTS

THIS SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT. *(IF ADDITIONAL SPACE IS NEEDED, USE SEPARATE SHEET.)*

Plant in Service	Installed Cost	Amortization & Depreciation	Net Plant in Ser
Seabrook	$27 512 051	$ 3 703 564	$23 808 487
Millstone 3	14 951 022	3 898 956	11 352 066
No. Hartland	16 034 380	2 811 234	13 223 146
Highgate	785 544	608 294	177 250
Other	19 667		19 667
	$59 302 664*	$ 11 022 048**	$48 580 616**

****

**** Includes Past-due Principal	$ 2 671 820	
" " Interest	34 296 559	

# Other Deferred Debits -Unapplied REA Payments	3 257 770	To current assets by CPA repo
	11 252	Seabrook Funding Clearing
	3 269 022	

G&T ACCOUNTS PAYABLE DETAIL - DECEMBER 31, 1993

PROJECTS: NORTH HARTLAND		
ACRES - NOTE PAYABLE	PAID-IN-FULL	-
PIZZAGALLI	PAID-IN-FULL	
N.E.T.	10,289	10,289
MILLSTONE 3 - NORTHEAST UTILITIES		
JT. CONS. INV.	462,602	
JT. TRANSM	13,845	
JT. SITE	8,140	
INTEREST	560,703	
		1,045,291
SEABROOK		
YAEC - PROJECT INV.	4,024,289	
PROP TAXES & FEES	191,033	
YAEC-INTEREST THRU 12/93	3,931,775	
PSNH-TRANS SPPT	107,354	
NEP SBRK-TWKBRY	75,661	
TOWN OF SEABROOK -P TAX	40,933	
LAWYERS	2,226	8,373,272
OPERATING INVOICES		
COE & FERC	11,950	
FERC	15,673	
PAPPONE (G,P&H)	13,575	
LaCAPRA	9,853	
BURAK&ANDERSON	12,384	
VEC- PR SERV&EXP	11,988	
MISC. INVOICES	22,796	98,219
ACCOUNTS PAYABLE-GENERAL		$9,527,071
ACCOUNTS PAYABLE-ASSOCIATED COMPANY (VEC)		$544,000
ACCOUNTS PAYABLE-CASH ADVANCED (VEC)		$1,268,000
TOTAL DECEMBER 93 ACCOUNTS PAYABLE		$11,339,071

VEGET SUMMARY OF REVENUES — SCHEDULE #1

FINANCIAL STATEMENT MONTH	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
CALENDER MONTH	DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	YEAR TOTAL
VERMONT ELECTRIC CO-OP.													
KWH (delivered)	9,770,990	10020320	9,338,030	9,788,750	6,059,610	5,824,730	5,678,900	6,571,740	6,840,950	6,317,530	7,399,290	8,723,460	92,334,300
MILLS	115.86	107.68	118.09	114.91	177.35	167.58	183.49	158.62	165.56	213.48	161.00	128.87	144.81
AMOUNT	1,132,059	1,079,017	1,102,727	1,124,796	1,074,667	976,108	1,042,018	1,042,430	$1,132,603	$1,348,640	$1,191,310	$1,124,176	$13,370,552
OTHER UTILITY	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP		GMP	GMP	
KWH	1,394,200	1,285,770	1,339,260	2,224,510	4,981,590	5,570,130	5,010,930	4,773,300	2,627,320		1,123,080	3,478,970	33,809,060
MILLS	25.45	26.46	25.94	24.73	28.55	24.54	24.08	24.66	25.12		27.26	25.75	25.52
AMOUNT	$35,482	$34,018	$34,740	$55,021	$142,221	$136,703	$120,667	$117,696	$66,002		$30,619	$89,567	$862,735
OTHER UTILITY	VM	VM	VM	VM	VM	VM	VM	VM			CVPSC		
KWH (delivered)	1,293,900	1,407,450	1,316,280	1,407,000	463,340	1,442,080	1,412,120	1,388,350			1,123,080		11,253,600
MILLS	26.75	25.72	26.54	25.73	31.81	20.65	22.40	24.84			20.00		24.44
AMOUNT	$34,615	$36,204	$34,928	$36,198	$14,737	$29,783	$31,625	$34,489			$22,462		$275,040
OTHER UTILITY									CMP	CMP			
KWH									1,488,530	1,019,150			2,507,680
MILLS									25.00	24.00			24.59
AMOUNT									$37,213	$24,460			$61,673
OTHER UTILITY													
KWH													0
MILLS													
AMOUNT													$0
'ENUES: ELECTRIC SALES													
KWH	12459090	12713540	11993570	13420260	11504540	12836940	12,101,950	12,733,390	10,956,800	7,336,680	9,645,450	12,202,430	139,904,640
MILLS	96.49	90.39	97.75	90.61	107.06	89.01	98.69	93.82	112.79	187.16	129.01	99.47	104.14
AMOUNT	1,202,156	1,149,239	1,172,395	1,216,015	1,231,625	1,142,594	$1,194,310	$1,194,615	$1,235,817	$1,373,099	$1,244,391	$1,213,743	$14,570,000
OTHER ELECTRIC REVENUES													
VT. MARBLE - TRANSM. LEASE	$1,976	$1,958	$1,912	$2,022	$1,097	$996	$961	$1,089	$1,008	$1,477	$987	$1,997	$17,481
CVPSC - TRANSM CAPACITY									$246	$775	$271	$611	$1,903
OTHER REVENUE													$0
TOTAL REVENUES	1,204,132	1,151,198	1,174,307	1,218,037	1,232,722	1,143,590	$1,195,271	$1,195,703	$1,237,072	$1,375,352	$1,245,648	$1,216,351	$14,589,384

SCHEDULE #2

VEG & T SUMMARY OF PURCHASED POWER COSTS

FINANCIAL STATEMENT MONTH	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
CALENDER MONTH	DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	YEAR TOTAL
MERRIMACK													
CAPACITY													
KW	1,909	1,909	1,909	1,909	1,909	1,909	1,909	1,909	1,909	1,909	1,909	1,909	22,908
UNIT COST: $/KW	7.02	4.89	5.53	6.06	5.85	5.73	12.22	7.24	5.96	6.06	7.67	6.56	6.73
AMOUNT	$13,395	$9,341	$10,562	$11,572	$11,168	$10,934	$23,322	$13,828	11,379	$11,559	$14,634	$12,520	$154,214
ENERGY													
KWH	1,314,890	1,162,720	1,203,680	1,257,760	608,430	50,340	995,510	1,233,210	1,149,330	1,254,690	1,093,750	1,131,610	12,455,920
UNIT COST: MILLS/KWH	17.25	17.48	17.47	17.08	17.49	29.59	18.47	17.43	17.61	16.83	16.49	18.80	17.52
AMOUNT	$22,684	$20,323	$21,032	$21,478	$10,643	$1,490	$18,391	$21,496	$20,234	$21,120	$18,032	$21,274	$218,197
TOTAL	$36,079	$29,665	$31,594	$33,051	$21,811	$12,424	$41,713	$35,324	$31,613	$32,679	$32,666	$33,794	$372,411
MERRIMACK-AVG COST - MILLS/KWH	27.44	25.51	26.25	26.28	35.85	246.79	41.90	28.64	27.51	26.05	29.87	29.86	29.90
VERMONT YANKEE													
CAPACITY													
KW	5,477	5,477	5,477	5,477	5,477	5,477	5,477	5,477	5,477	5,477	5,477	5,477	65,724
UNIT COST: $/KW	26.91	19.87	20.51	23.44	24.35	22.19	21.20	24.09	30.52	47.46	28.57	23.45	26.04
AMOUNT	$147,371	$108,804	$112,340	$128,356	$133,359	$121,534	$116,102	$131,943	$167,134	$259,957	$156,457	$128,411	$1,711,767
ENERGY													
KWH	4,045,020	4,049,740	3,638,130	4,034,400	2,494,180	3,964,530	3,749,900	3,757,840	2,974,650	0	688,170	3,912,620	37,309,180
UNIT COST: MILLS/KWH	6.00	5.79	5.84	5.80	6.06	5.80	5.83	5.83	5.95	N/A	6.67	4.99	5.86
AMOUNT	$24,258	$23,460	$21,259	$23,383	$15,126	$23,000	$21,858	$21,901	$17,694	$2,401	$4,587	$19,525	$218,452
TOTAL	$171,629	$132,264	$133,598	$151,739	$148,485	$144,534	$137,960	$153,843	$184,828	$262,358	$161,044	$147,936	$1,930,219
VT-YANKEE-AVG COST - MILLS/KWH	42.43	32.66	36.72	37.61	59.53	36.46	36.79	40.94	62.13	N/A	234.02	37.81	51.74
HIGHGATE I													
CAPACITY													
KW	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	48,240
UNIT COST: $/KW	5.68	5.68	5.14	5.69	5.50	5.69	5.50	5.68	5.68	5.41	5.59	5.41	5.55
AMOUNT	$22,848	$22,848	$20,647	$22,877	$22,127	$22,863	$22,111	$22,848	$22,848	$21,731	$22,455	$21,731	$267,932
ENERGY													
KWH	1,630,200	1,631,750	1,580,410	1,555,550	1,369,300	1,240,520	1,381,590	1,310,000	1,519,010	1,460,990	1,537,130	1,392,000	17,608,450
UNIT COST: MILLS/KWH	16.89	16.98	16.98	17.00	17.15	17.40	17.63	17.75	17.75	17.81	17.78	17.67	17.38
AMOUNT	$27,539	$27,705	$26,835	$26,444	$23,483	$21,585	$24,357	$23,251	$26,965	$26,025	$27,324	$24,599	$306,114
ADJUSTMENT & VELCO EXP	($4,958)	($4,179)	$782	$547	$2,477	$686	$68	$2,336	$895	$9,231	$524	$712	$9,120
TOTAL	$45,429	$46,374	$48,264	$49,868	$48,087	$45,134	$46,536	$48,435	$50,707	$56,987	$50,303	$47,042	$583,166
HIGHGATE 1-AVG COST- MILLS/KWH	27.87	28.42	30.54	32.06	35.12	36.38	33.68	36.97	33.38	39.01	32.73	33.79	33.12

	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
	DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	SUBTOTAL
SPOT PURCHASES	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	GMP	*
						A&B	A&B	A&B	A&B	A&B	A&B	A&B	
KW	5,000	5,000	5,000	4,000	4,000	3,000	3,000	4,000	4,000	3,000	4,000	3,000	47,000
UNIT COST: $/KW	2.75	2.75	2.75	2.75	2.75	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.62
AMOUNT	$13,750	$13,750	$13,750	$11,000	$11,000	$7,500	$7,500	$10,000	$10,000	$7,500	$10,000	$7,500	$123,250
KWH	105,000	0	0	136,000	45,000	3,000	0	0	203,000	45,000	64,000	3,000	604,000
UNIT COST: MILLS/KWH	30.90	ERR	ERR	29.00	29.22	28.00	28.00	28.00	29.53	29.33	29.25	28.00	29.57
AMOUNT	$3,245	$0	$0	$3,944	$1,315	$84	$0	$0	$5,994	$1,320	$1,872	$84	$17,858
TOTAL	$16,995	$13,750	$13,750	$14,944	$12,315	$7,584	$7,500	$10,000	$15,994	$8,820	$11,872	$7,584	$141,108
-AVG COST - MILLS/KWH	161.86	ERR	ERR	109.88	273.67	2528.00	N/A	N/A	78.79	196.00	185.50	2528.00	233.62
SPOT PURCHASES						GMP	GMP	GMP	GMP	GMP	GMP	GMP	
CAPACITY						BERLIN A&B	BERLIN A&B	BERLIN A&B	BERLIN A&B	BERLIN A&B	BERLIN A&B	BERLIN A&B	
KW						2,000	2,000	2,000	2,000	2,000	2,000	2,000	14,000
UNIT COST: $/KW						0.33	0.33	0.33	0.33	0.33	0.33	0.30	0.33
AMOUNT						$667	$667	$667	$667	$667	$667	$600	$4,600
ENERGY													
KWH						946	0	9,492	13,891	6,936	17,973	15,090	64,328
UNIT COST: MILLS/KWH						74.69	74.71	71.72	69.20	71.72	74.71	83.15	74.74
AMOUNT						$71	$0	$681	$961	$497	$1,343	$1,255	$4,808
TOTAL						$737	$667	$1,347	$1,628	$1,164	$2,009	$1,855	$9,408
:AVG COST - MILLS/KWH						779.42	N/A	141.95	117.19	167.84	111.80	122.91	146.24
NORTHEAST UTILITIES												NEP	
CAPACITY												BEAR SWAMP	
KW	8,000	8,000	8,000	8,000	8,000	GONE	GONE	GONE	GONE	GONE	GONE	1,000	41,000
UNIT COST: $/KW	1.22	1.35	1.35	1.35	1.35							2.08	1.35
AMOUNT	$9,768	$10,834	$10,834	$10,834	$10,834							$2,083	$55,187
ENERGY											NEP-ENERGY		
											OPPORTUNITY PURCHASE -		
KWH	15,122	0	0	19,157	13,225						48,000		95,504
UNIT COST: MILLS/KWH	66.13	ERR	ERR	63.27	0.30						23.50		35.27
AMOUNT	$1,000	$12	$12	$1,212	$4						$1,128		$3,368
TOTAL	$10,768	$10,846	$10,846	$12,046	$10,838	$0	$0	$0	$0	$0	$1,128	$2,083	$58,555
NU TURB.-AVG COST - MILLS/KWH	712.08	ERR	ERR	628.80	819.51						23.50	CAPACITY	613.12
SPOT PURCHASES									HO-TERTIARY	HO-TERTIARY	HO-TERTIARY		
CAPACITY - KW									2,000	2,000	3,500		
ENERGY													
KWH									1,452,760	1,428,000	2,548,000		5,428,760
UNIT COST:MILLS/KWH									19.50	21.00	18.00		19.19
AMOUNT									28,329	29,988	45,864		$104,181

	JAN 93 DEC 92	FEB 93 JAN 93	MAR 93 FEB 93	APR 93 MAR 93	MAY 93 APR 93	JUN 93 MAY 93	JUL 93 JUN 93	AUG 93 JUL 93	SEP 93 AUG 93	OCT 93 SEP 93	NOV 93 OCT 93	DEC 93 NOV 93	12 MONTH SUBTOTAL
NEPOOL - ENERGY													
SALES													
KWH	1,224,070	968,650	720,650	744,420	737,930	413,080	1,068,400	491,490	746,750	605,400	676,450	259,750	8,657,040
UNIT COST:MILLS/KWH	11.32	9.08	11.10	9.15	3.69	5.16	9.94	8.99	9.00	9.04	8.99	8.42	8.99
AMOUNT	$13,855	$8,795	$8,001	$6,810	$2,719	$2,133	$10,618	$4,421	$6,717	$5,476	$6,080	$2,188	$77,812
NEPOOL - PURCHASES - ENERGY													
KWH	1,002,780	1,513,470	869,130	1,208,610	2,651,570	1,311,610	707,420	1,470,950	1,173,070	1,659,540	1,833,480	1,486,160	16,887,790
UNIT COST: MILLS/KWH	15.08	19.01	19.58	22.58	20.72	16.39	10.84	19.35	17.25	20.82	19.06	24.16	19.33
AMOUNT	$15,122	$28,773	$17,016	$27,290	$54,932	$21,493	$7,671	$28,465	$20,231	$34,556	$34,948	$35,907	$326,405
EXPENSES	$268	$2,579	$3,194	$1,614	$3,473	$3,794	$4,246	$4,318	$3,406	$3,706	$3,600	$2,591	$36,789
NET NEPOOL KWH	(221,290)	544,820	148,480	464,190	1,913,640	898,530	(360,980)	979,460	426,320	1,054,140	1,157,030	1,226,410	8,230,750
TOTAL	$1,535	$22,558	$12,210	$22,094	$55,686	$23,154	$1,298	$28,362	$16,921	$32,786	$32,468	$36,310	$285,382
NEPOOL ENERGY.-AVG -MILLS/KWH	-6.94	41.40	82.23	47.60	29.10	25.77	-3.60	28.96	39.69	31.10	28.06	29.61	34.67
						GMP	GMP	GMP					
S.T. PURCHASES	N/A	N/A	N/A	N/A	N/A	VERGENNES	DIES.	VERG DIESL					
KW						2,500	2,500	1,500					6,500
UNIT COST: $/KW													
AMOUNT						NONE	NONE						$0
ENERGY													
KWH						3,361	0	21,300					24,661
UNIT COST: MILLS/KWH						66.89	61.99	59.70					
AMOUNT						$225	$0	$1,272					$1,496
TOTAL	$0	$0	$0	$0	$0	$225	$0	$1,272					$1,496
S.T.-AVG COST- MILLS/KWH	N/A	N/A	N/A	N/A	N/A	66.89		59.70					
S.T. PURCHASES	N/A	N/A	N/A	N/A	N/A	CV SYS PUR	CV SYS PUR	CV SYS PUR	CV SYS PUR	CV SYS PUR	CV SYS PUR		
KW						1,000	1,000	1,000	1,000	1,000	1,000		6,000
UNIT COST: $/KW						3.50	3.00	3.00	3.00	3.00	3.00		3.08
AMOUNT						$3,500	$3,000	$3,000	$3,000	$3,000	$3,000		$18,500
ENERGY													
KWH						407,000	239,000	251,000	374,000	201,000	185,000		1,657,000
UNIT COST: MILLS/KWH						17.41	17.28	19.74	21.78	23.05	21.39		19.86
AMOUNT						$7,086	$4,129	$4,954	8,144	4,634	3,958		$32,905
TOTAL	$0	$0	$0	$0	$0	$10,586	$7,129	$7,954	$11,144	$7,634	$6,958		$51,405
S.T.-AVG COST- MILLS/KWH						26.01	29.83	31.69	29.80	37.98	37.61		31.02
VT MARBLE SPNNG RESERVE	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$12,000
(A/C 557 + 557.1) EXPENSES	$325	$325	$238	$2,163	$439	$214	$349	$821	$720	$1,811	$2,407	$2,464	$12,274
(A/C 555.1) PHASE I													
EXPENSE	$4,620	$4,391	$4,522	$4,517	$4,208	$4,552	$4,509	$4,593	$4,430	$4,330	$3,787	$4,368	$52,827
REVENUE-CR	$0	($3)							($2)	($10)			($15)
DIVIDEND-CR			($6,597)			($6,597)				($6,597)		($5,864)	($25,655)
NET PHASE I PROFIT,-, OR LOSS	$4,620	$4,388	($2,075)	$4,517	$4,208	($2,045)	$4,509	$4,593	$4,428	($2,277)	$3,787	($1,496)	$27,157
TOTAL KWH	6,888,942	7,389,030	6,570,700	7,467,057	6,443,775	6,568,227	6,005,020	7,562,302	8,112,961	5,450,756	7,339,053	7,680,730	83,478,553
TOTAL PURCHASED POWER COSTS	$288,380	$261,170	$256,021	$291,422	$302,869	$250,144	$248,661	$292,952	$347,311	$439,547	$351,506	$284,435	$3,614,417
AVG. PURCH. PWR. - MILLS/KWH	41.86	35.35	38.96	39.03	47.00	38.08	41.41	38.74	42.81	80.64	47.90	37.03	43.30

FINANCIAL STATEMENT MONTH	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
CALENDER MONTH	DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	SUBTOTAL
NORTH HARTLAND													
KWH	1,129,600	1,022,000	383,000	557,600	477,600	959,200	515,200	75,600	99,400	148,200	296,000	712,000	6,375,400
INTEREST													
LONG TERM DEBT	97,467	88,035	97,467	94,069	97,205	94,069	92,658	77,015	73,043	76,847	74,368	76,847	1,039,090
SHORT TERM DEBT	82,596	74,197	81,795	81,580	84,696	86,492	91,921	92,468	90,351	94,041	91,597	94,705	1,046,439
PROPERTY TAX	9,817	9,830	9,830	9,830	9,830	9,830	6,927	6,927	12,610	12,610	12,610	12,610	123,261
PROPERTY INSURANCE	2,746	2,746	2,746	2,746	2,746	2,746	2,746	2,746	2,746	2,746	3,202	3,979	34,641
DEPRECIATION													
TRANSMISSION	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167	14,004
GENERATION	26,667	26,667	26,667	26,667	26,667	26,667	26,667	26,667	26,667	26,667	26,667	26,667	320,004
OPERATION & MAINTENANCE	9,807	10,192	5,879	4,983	7,441	6,877	6,131	2,034	10,118	4,228	5,238	33,047	105,973
TOTAL	$230,267	$212,833	$225,551	$221,042	$229,752	$227,849	$228,217	$209,024	$216,702	$218,306	$214,849	$249,022	$2,683,413
NORTH HARTLAND - MILLS/KWH	203.85	208.25	588.91	396.42	481.06	237.54	442.97	2764.86	2180.10	1473.05	725.84	349.75	420.90
MILLSTONE													
KWH	2,226,900	2,679,700	2,615,800	2,689,200	1,893,100	2,881,500	2,761,500	2,661,000	0	0	0	1,723,610	22,132,310
INTEREST													
LONG TERM DEBT	79,888	72,157	79,888	77,126	79,697	77,126	77,466	70,326	67,440	70,184	67,920	70,184	889,399
SHORT TERM DEBT	57,277	51,679	50,533	63,474	59,002	58,910	63,049	62,974	61,395	64,271	62,495	64,674	719,731
PROPERTY TAX	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	8,500	(838)	92,662
PROPERTY INSURANCE	INCLUDED IN O&M												
DEPRECIATION	35,313	35,320	35,321	35,325	35,333	35,342	35,345	35,356	35,452	35,418	35,429	35,437	424,391
OPERATION & MAINTENANCE	42,705	42,923	30,021	33,707	34,727	40,826	41,402	39,288	60,382	95,644	74,672	58,223	594,521
TRANSMISSION EXPENSE	2,315	1,739	1,898	1,646	1,502	1,809	1,718	1,461	678	1,658	1,745	1,856	20,025
ADMINISTRATIVE & GENERAL													
FUEL EXPENSE-RE:GENERATION	13,479	13,158	13,524	9,499	14,494	13,891	13,380	(18)	(17)	(38)	7,661	14,523	113,536
FUEL EXPENSE-ADJ PRIOR PERI	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(8,250)	(99,000)
TOTAL	$231,226	$217,226	$211,435	$221,027	$225,004	$228,153	$232,610	$209,636	$225,581	$267,386	$250,172	$235,809	$2,755,265
MILLSTONE 3 - MILLS/KWH	103.83	81.06	80.83	82.19	118.85	79.18	84.23	78.78	N/A	N/A	N/A	136.81	124.49
SEABROOK UNIT 1													
KWH	3,103,700	2,585,300	3,196,000	3,537,900	3,418,600	3,165,100	3,427,400	3,132,700	3,531,500	2,417,900	2,664,500	2,791,500	36,971,700
INTEREST													
LONG TERM DEBT	84,772	76,568	84,772	81,890	84,619	81,890	81,491	70,775	67,500	70,688	68,408	70,688	924,060
SHORT TERM DEBT	93,968	87,470	94,479	81,386	96,266	94,222	98,783	98,931	101,165	105,262	101,125	104,684	1,157,740
PROPERTY TAX	15,680	15,680	15,680	15,680	15,680	(2,503)	12,650	12,650	12,650	12,650	12,650	(25,369)	113,776
PROPERTY INSURANCE	INCLUDED IN O&M												
DEPRECIATION--inc Decomm.	63,489	63,639	63,663	63,715	63,724	63,702	63,703	63,715	63,756	63,759	63,679	63,776	764,320
OPERATION & MAINTENANCE	57,349	26,611	43,525	41,193	35,774	46,152	30,027	38,039	42,958	43,949	43,205	62,791	511,573
TRANSMISSION EXPENSE	624	1,303	0						0				1,927
ADMINISTRATIVE & GENERAL													
FUEL EXPENSE	21,882	27,051	30,905	29,255	27,104	29,326	26,832	30,208	19,978	20,649	23,452	29,263	315,905
TOTAL	$337,764	$298,323	$333,023	$313,118	$323,167	$312,789	$313,485	$314,316	$308,006	$316,958	$312,519	$305,833	$3,789,302
SEABROOK 1 - MILLS/KWH	108.84	115.39	104.20	88.50	94.53	98.82	91.46	100.33	87.22	131.09	117.29	109.56	102.49
GRAND TOTAL SCHEDULE 3a	$799,257	$728,382	$770,009	$755,186	$777,923	$768,791	$774,312	$732,976	$750,289	$802,650	$777,540	$790,664	$9,227,979

VEC & T SUMMARY OF TRANSMISSION,
GENERATION, INTEREST, A & G EXPENSES

SCHEDULE #3b

FINANCIAL STATEMENT MONTH	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
CALENDER MONTH	DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	SUBTOTAL
TRANSMISSION EXPENSE													
MISC	22	40	54	27		492	483	608	576	1,054	1,593	503	5,454
VELCO	26,307	37,833	37,654	41,433	39,489	37,657	36,957	38,222	39,826	39,794	36,922	42,668	454,762
NORTHEAST UTILITIES /PSNH	(3,673)	2,387	3,753	3,773	3,769	1,407	1,379	1,403	1,418	1,386	1,460	1,438	19,900
NEW ENGLAND POWER	5,750	10,100	5,750	8,650	5,750	1,450	1,450	1,733	1,409	1,409	1,409	1,409	46,267
CVPSC - N. HARTLAND	7,217	7,217	7,217	7,217	7,217	7,217	7,217	7,217	7,217	7,217	7,217	(7,612)	71,772
TOTAL	$35,623	$57,576	$54,428	$61,100	$56,225	$48,223	$47,486	$49,182	$50,445	$50,860	$48,601	$38,407	$598,155
AMORTIZATIONS													
PILGRIM II	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	35,496
SEABROOK II	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	6,406	76,872
HIGHGATE	6,167	6,167	6,167	6,167	6,167	6,167	6,167	6,167	6,167	6,167	6,167	6,167	74,000
TOTAL	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$15,531	$186,368
INTEREST EXPENSES													
LONG TERM (P II+S II)	15,144	13,678	15,334	14,636	15,123	14,636	14,884	13,952	13,388	13,940	13,490	13,987	172,192
SHORT TERM	19,427	16,809	18,208	17,708	18,486	21,540	21,966	22,586	15,195	15,809	15,144	15,716	218,593
GAIN ON DISP. PROPERTY													
INTEREST INCOME -	(2,436)	(1,816)	(2,014)	(1,126)	(1,001)	(307)	0			(858)			(9,559)
- ALSO SEE PHASE 1			(6,597)			(6,597)				(6,597)		(5,864)	(25,655)
TOTAL	$32,134	$28,672	$24,931	$31,217	$32,608	$29,271	$36,850	$36,538	$28,583	$22,294	$28,634	$23,839	$355,571
GENERAL & ADMINISTRATIVE													
DIRECTORS & MTGS	125	949	1,000	1,453	1,731	0	1,197	0	0	121	1,830	0	8,407
INSURANCE & START UP	4,271	4,245	4,260	4,260	4,260	4,260	4,260	4,260	9,902	4,260	Sept Err	4,260	52,498
SALARIES	6,429	6,197	5,946	8,365	5,885	6,782	6,304	4,896	7,367	6,829	6,922	7,417	79,339
CONSULTANTS	5,959	38,309	5,301	11,864	7,147	2,572	2,113	1,213	3,807	4,910	8,892	8,006	100,092
LEGAL	16,292	9,814	35,894	37,006	27,571	16,920	57,855	57,104	23,376	27,430	5,643	43,602	358,506
OFFICE EXPENSES & DUES	54	322	960	524	791	196	615	962	350	805	493	105	6,178
BILLING	77	29	27	110	182	43	87	90	111	116	56	86	1,014
NRECA DUES						1,150							1,150
GROSS REVENUE TAX						(291)							
TOTAL	$33,208	$59,867	$53,387	$63,582	$47,567	$31,631	$72,432	$68,524	$44,913	$44,471	$23,837	$63,475	$606,893
OTHER DEDUCT.- ABANDONED PROJ.													$0
TOTAL (SCHEDULES 3a & 3b)	$915,752	$890,028	$918,296	$926,616	$929,853	$893,446	$946,611	$902,752	$889,761	$935,805	$894,143	$931,9[illegible]6	$10,974,967
TOTAL PURCHASED PWR (SCHED. 2)	$288,380	$261,170	$256,021	$291,422	$302,869	$250,144	$248,661	$292,952	$347,311	$439,547	$351,506	$284,435	$3,614,417
MARGINS													
TOTAL COST OF SERVICE	$ 1,204,132	1,151,198	1,174,307	1,218,037	1,232,722	1,143,590	$1,195,271	$1,195,703	$1,237,072	$1,375,352	$1,245,648	$1,216,351	$14,589,384

VEG & T REVENUES WITH LINE LOSSES SCHEDULE #4

FINANCIAL STATEMENT MONTH		JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	DEC 93	12 MONTH
CALENDER MONTH		DEC 92	JAN 93	FEB 93	MAR 93	APR 93	MAY 93	JUN 93	JUL 93	AUG 93	SEP 93	OCT 93	NOV 93	SUBTOTAL
TOTAL COST OF SERVICE														
KWH		13348742	13676030	12765500	14251757	12233075	13574027	12,709,120	13,431,602	11,743,861	8,016,856	10,299,553	12,907,840	148,957,963
UNIT COST		90.21	84.18	91.99	85.47	100.77	84.25	94.05	89.02	105.34	171.56	120.94	94.23	97.94
AMOUNT	$	1,204,132	1,151,198	1,174,307	1,218,037	1,232,722	1,143,590	$1,195,271	$1,195,703	$1,237,072	$1,375,352	$1,245,648	$1,216,351	$14,589,384
TRANSMISSION LINE LOSS		839,652	962,490	771,930	831,497	728,535	737,087	607,170	698,212	787,061	680,176	654,103	705,410	9,053,323
POWER AVAILABLE FOR SALE														
KWH		12459090	12713540	11993570	13420260	11504540	12836940	12,101,950	12,733,390	10,956,800	7,336,680	9,645,450	12,202,430	139,904,640
UNIT COST		96.65	90.55	97.91	90.76	107.15	89.09	98.77	93.90	112.90	187.46	129.14	99.68	104.28
AMOUNT	$	1,204,132	1,151,198	1,174,307	1,218,037	1,232,722	1,143,590	$1,195,271	$1,195,703	$1,237,072	$1,375,352	$1,245,648	$1,216,351	$14,589,384
SALES														
VERMONT ELECTRIC CO-OP.														
KWH		9,770,990	10020320	9,338,030	9,788,750	6,059,610	5,824,730	5,678,900	6,571,740	6,840,950	6,317,530	7,399,290	8,723,460	92,334,300
UNIT COST-MILLS/KWH		115.86	107.68	118.09	114.91	177.35	167.58	183.49	158.62	165.56	213.48	161.00	128.87	144.81
AMOUNT	$	1,132,059	1,079,017	1,102,727	1,124,796	1,074,667	$976,108	$1,042,018	$1,042,430	$1,132,603	$1,348,640	$1,191,310	$1,124,176	$13,370,552
VT MARBLE LEASE														
KWH														0
UNIT COST-MILLS/KWH														
AMOUNT		$1,976	$1,958	$1,912	$2,022	$1,097	$996	$961	$1,089	$1,008	$1,477	$987	$1,997	$17,481
CV LEASE - TRANSMISSION CAPACI		$0	$0	$0	$0	$0	$0	$0	$0	$246	$775	$271	$611	$1,903
OTHER UTILITIES														
KWH		2,688,100	2,693,220	2,655,540	3,631,510	5,444,930	7,012,210	6,423,050	6,161,650	4,115,850	1,019,150	2,246,160	3,478,970	47,570,340
UNIT COST-MILLS/KWH		26.08	26.07	26.23	25.12	28.83	23.74	23.71	24.70	25.08	24.00	23.63	25.75	25.21
AMOUNT		$70,096	$70,222	$69,668	$91,219	$156,958	$166,486	$152,292	$152,185	$103,215	$24,460	$53,080	$89,567	$1,199,448
TOTAL SALES (KWH)		12459090	12713540	11993570	13420260	11504540	12836940	12,101,950	12,733,390	10,956,800	7,336,680	9,645,450	12,202,430	139,904,640
TOTAL SALES (REVENUES)	$	1,204,132	1,151,198	1,174,307	1,218,037	1,232,722	1,143,590	$1,195,271	$1,195,703	$1,237,072	$1,375,352	$1,245,648	$1,216,351	$14,589,384
TOTAL SALES (UNIT COST)		96.65	90.55	97.91	90.76	107.15	89.09	98.77	93.90	112.90	187.46	129.14	99.68	104.28

USDA-REA

OPERATING REPORT - SALES OF ELECTRICITY

BORROWER DESIGNATION: Vermont 12 Hampshire

This data will be used by REA to review your financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

YEAR ENDING: December 31, 1993

REA USE ONLY

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

PURCHASER (a)	NO. OF PURCHASERS (b)	ANNUAL PEAK DEMAND (kW) (c)	MWh BILLED (d)	AMOUNT BILLED ($) (e)	MILLS PER kWh (f)
1. Sales to Ultimate Consumers *(Totals only for this item.)*					
SALES FOR RESALE - REGULAR SALES TO REA BORROWERS *(List separately)*					
2.					
3.					
4. -Intentionally Blank-					
5.					
6.					
7.					
8.					
9.					
10.					
11.					
12.					
13.					
14.					
15.					
16.					
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30.					
31.					
32.					
33.					
34.					
35.					
36.					
37.					
38.					
39. TOTAL Regular Sales to REA Borrowers *(Sum of lines 2 thru 38)*					

Public reporting burden for this collection of information is estimated to average 24.25 hours (REA Form 12a-i) per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Department of Agriculture, Clearance Officer, OIRM, AG Box 7630, Washington, DC 20250; and to the Office of Management and Budget, Paperwork Reduction Project (OMB #0572-0017), Washington, DC 20503. OMB FORM NO. 0572-0017, Expires 12/31/94.

USDA-REA

OPERATING REPORT - SALES OF ELECTRICITY

BORROWER DESIGNATION: Vermont 12 Hampshire

YEAR ENDING: December 31, 1993

REA USE ONLY

PURCHASER (a)	NO. OF PURCHASERS (b)	ANNUAL PEAK DEMAND (kW) (c)	MWh BILLED (d)	AMOUNT BILLED ($) (e)	MILLS PER kWh (f)
SALES FOR RESALE - SPECIAL SALES TO REA BORROWERS *(List separately)*					
40.					
41. Vermont Electric Cooperative, Inc. (Vermont 7)		33 197	92 334.3	13 370 552	144.81
42.					
43.					
44.					
45.					
46.					
47.					
48.					
49.					
50.					
51. TOTAL Special Sales to REA Borrowers *(Sum of lines 40 thru 50)*		33 197	92 334.3	13 370 552	144.81
52. TOTAL Sales to REA Borrowers *(Sum of lines 39 + 51)*		33 197	92 334.3	13 370 552	144.81
SALES FOR RESALE OTHER THAN REA BORROWERS *(List separately)*					
53. Green Mtn. Power Corp.		9 000	33 809.0	862 735	25.52
54. Vermont Marble Company		2 000	10 130.5	252 578	24.93
55. Central Vt. Public Service Corp.		2 000	1 123.1	22 462	20.00
56. Central Maine Power Co.		2 000	2 507.7	61 673	24.59
57.					
58.					
59.					
60.					
61.					
62.					
63.					
64.					
65.					
66.					
67.					
68.					
69.					
70.					
71.					
72.					
73.					
74.					
75. TOTAL Sales to Other Than REA Borrowers *(Sum of lines 53 thru 74)*		15 000	47 570.3	1 199 448	25.21
76. TOTAL Sales for Resale *(Sum of lines 52 + 75)*		48 197	139 904.6	14 570 000	104.14
77. TOTAL Sales *(Sum of lines 1 + 76)*		48 197	139 904.6	14 570 000	104.14

USDA-REA

OPERATING REPORT - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION: Vermont 12 Hampshire

This data will be used by REA to review your financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

YEAR ENDING: December 31, 1993

REA USE ONLY

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

SOURCE OF ENERGY (a)	NO. OF PLANTS (b)	NAMEPLATE CAPACITY (kWh) (c)	ANNUAL PEAK DEMAND (kW) (d)	NET ENERGY RECEIVED BY SYSTEM (MWh) (e)	COST ($) (f)	MILLS PER kWh (g)
GENERATED IN OWN PLANT *(Details on Forms 12d, e, f, and g)*						
1. Fossil Steam						
2. Nuclear Millstone 3 & Seabrook (joint ownerships)	2	8 791		59 104.01	6 544 567	110.73
3. Hydro No. Hartland	1	4 000		6 375.40	2 683 413	420.90
4. Internal Combustion and Other						
5. TOTAL in Own Plant *(Sum of lines 1 thru 4)*	3	12 791		65 479.41	9 227 980	140.93
PURCHASED POWER *(List each supplier separately)*		REA USE ONLY CODE				
6. Vermont Electric Power Company- Merrimack 2			1 909	12 455.9	372 411	29.90
7. - Vermont Yankee			5 477	37 309.2	1 930 219	51.74
8. - HQ Tertiary			3 500	5 428.8	104 181	19.19
9. - NEPOOL Purchases				16 887.8	363 194	21.51
10. - NEPOOL Sales				(8 657.0)	(77 812)	8.99
11. State of Vermont-Dept. of Public Service-Highgate 1			4 020	17 608.4	583 166	33.12
12. Northeast Utilities - - Gas Turbines			8 000	47.5	55 344	1165.14
13. Green Mountain Power Corp. - System Power			4 000	604.0	141 108	233.62
14. - Berlin A&B			2 000	64.3	9 408	146.24
15. - Vergennes Diesel			2 500	24.7	1 496	60.57
16. New England Power Co. - System Power				48.0	1 128	23.50
17. Vermont Marble Co. - Spinning Reserve					12 000	
18. Central Vt. Public Service Corp. System Power			1 000	1 657.0	51 405	31.02
19. New England Power Co. - Pumped Storage Capacity			1 000		2 083	
20.						
21. TOTAL Power Purchased *(Sum of lines 6 thru 20)*				83 478.6	3 549 331	42.52
INTERCHANGED POWER						
22. Received Into System *(Gross)*						
23. Delivered Out of System *(Gross)*						
24. Net Interchange *(Line 22 minus 23)*						
TRANSMISSION FOR OR BY OTHERS - (WHEELING)						
25. Received Into System						
26. Delivered Out of System						
27. Net Energy Wheeled *(Line 25 minus 26)*						
28. TOTAL Energy Available for Sale *(Sum of lines 5 + 21 + 24 + 27)*				148 958.01		
29. TOTAL Sales *(Form 12b, line 77)*				139 904.6		
30. Energy Furnished to Others Without Charge						
31. Energy Used by Borrower *(Excluding Station Use)*						
32. TOTAL Energy Accounted For *(Sum of lines 29 thru 31)*				139 904.6		
33. Energy Losses - MWh *(Line 28 minus 32)*				9 053.41		
34. Energy Losses - Percentage [(Line 33 divided by line 28) x 100]				6.1 %		

Public reporting burden for this collection of information is estimated to average 24.25 hours (REA Forms 12a-i) per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Department of Agriculture, Clearance Officer, OIRM, Room 404-W, Washington, DC 20250, and to the Office of Management and Budget, Paperwork Reduction Project (OMB #0572-0017), Washington, DC 20503. OMB FORM NO. 0572-0017, Expires 12/31/94.

USDA - REA OPERATING REPORT - HYDRO PLANT	This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.	
	BORROWER DESIGNATION Vermont 12 Hampshire	REA USE ONLY
	PLANT North Hartland Hydro	
INSTRUCTIONS - Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.	YEAR ENDING December 31, 1993	

SECTION A. HYDRO GENERATING UNITS

LINE NO.	UNIT NO. (a)	SIZE (kW) (b)	GROSS GENERATION (MWh) (c)	OPERATING HOURS: IN SERVICE (d)	ON STANDBY (e)	OUT OF SERVICE: Scheduled (f)	Unscheduled (g)
1.	1	4 000	6 297	2 037	6 171	0	552
2.							
3.							
4.							
5.							
6.	TOTAL	4 000	6 297	2 037	6 171	0	552
7.	Station Service (MWh)		157				
8.	Net Generation (MWh)		6 140				
9.	Station Service % of Gross		2.49				

HYDRAULIC DATA

ITEM	(a) MAXIMUM	(b) MINIMUM
1. POOL ELEVATION (Ft.)	487[1]	412.5[2]
2. TAIL RACE ELEVATION (Ft.)	358	352
WATER SPILLED	☒ YES	☐ NO

Not Applicable SECTION B. LABOR REPORT Contractor costs in section D

LINE NO.	ITEM	VALUE	LINE NO.	ITEM	VALUE
1.	No. Emp. Full Time (inc. Superintendent)		5.	Maint. Plant Payroll ($)	
2.	No. Emp. Part Time		6.	Other Accounts Plant Payroll ($)	
3.	Total Emp. - Hrs. Worked		7.	TOTAL Plant Payroll ($)	
4.	Oper. Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

LINE NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Min. Gross Maximum Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

LINE NO.	PRODUCTION EXPENSE	ACCOUNT NO.	AMOUNT ($) (a)	MILLS/NET kWh (b)
1.	Operation, Supervision and Engineering	535		
2.	Water for Power	536	6 957	
3.	Hydraulic Expenses	537	27 672	4.51
4.	Electric Expenses	538	7 295	1.19
5.	Miscellaneous Hydraulic Power Generation Expenses	539	347	0.06
6.	Rents	540	24 479	3.99
7.	OPERATION EXPENSES (1 thru 6)			
8.	Maintenance, Supervision and Engineering	541	66 750	10.87
9.	Maintenance of Structures	542	6 757	
10.	Maintenance of Reservoirs, Dams and Waterways	543		
11.	Maintenance of Electric Plant	544		
12.	Maintenance of Miscellaneous Hydraulic Plant	545	32 467	
13.	MAINTENANCE EXPENSES (8 thru 12)			
14.	TOTAL PRODUCTION EXPENSES (7 + 13)		39 224	6.39
15.	Depreciation		105 974	17.26
16.	Taxes	403.3	320 004	
17.	Interest	408	123 261	
18.	Insurance	427	2 032 660	
19.	TOTAL FIXED COSTS (15 thru 18)	924 925 926	34 641	
20.	POWER COST (14 + 19)		2 510 566	408.89
			2 616 540	426.15

REMARKS (Including Unscheduled Outages)

1. ACOE Flood Control Operation 4/19/93
2. ACOE Maintenance Draw-Down

REA Form 12e (Rev. 12-93)

USDA - REA

OPERATING REPORT - NUCLEAR PLANT

This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

BORROWER DESIGNATION: Vermont 12 Hampshire	REA USE [illegible]Y
PLANT: Seabrook I - Total Plant	
YEAR ENDING: December 31, 1993	

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

SECTION A. BOILERS AND GENERATING UNITS

LINE NO.	UNIT NO. (a)	TIMES STARTED (b)	SIZE (kW) (c)	GROSS GENERATION (MWh) (d)	OPERATING HOURS: IN SERVICE (e)	ON STANDBY (f)	OUT OF SERVICE: Scheduled (g)	Unscheduled (h)
1.			1 197 000		8 096			
2.								
3.								
4.								
5.								
6.	TOTAL							
7.	Station Service (MWh)							
8.	Net Generation (MWh)			9 046 805				
9.	Station Service % of Gross							

SECTION B. LABOR REPORT

LINE NO.	ITEM	VALUE	LINE NO.	ITEM	VALUE
1.	No. Emp. Full Time (inc. Superintendent)		5.	Maint. Plant Payroll ($)	
2.	No. Emp. Part Time		6.	Other Accounts Plant Payroll ($)	
3.	Total Emp.-Hrs. Worked		7.	TOTAL Plant Payroll ($)	
4.	Oper. Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

LINE NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Minute Gross Maximum Demand (kW)	
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

LINE NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)
1.	Operation, Supervision and Engineering	517		
2.	Fuel	518.1		
3.	Less Fuel Acquisition Adjustment	518.2		
4.	NET FUEL EXPENSE (2 - 3)			
5.	Coolants and Water	519		
6.	Steam Expenses	520		
7.	Steam From Other Sources	521		
8.	Electric Expenses	523		
9.	Miscellaneous Nuclear Power Expenses	524		
10.	Rents	525		
11.	OPERATION EXPENSES (1 + 4 thru 10)			
12.	Maintenance, Supervision and Engineering	528		
13.	Maintenance of Structures	529		
14.	Maintenance of Reactor Plant Equipment	530		
15.	Maintenance of Electric Plant	531		
16.	Maintenance of Miscellaneous Nuclear Plant	532		
17.	MAINTENANCE EXPENSES (12 thru 16)			
18.	Reactor Credits			
19.	TOTAL PRODUCTION EXPENSES (11 + 17 - 18)			
20.	Depreciation	403.2		
21.	Taxes	408		
22.	Interest	427		
23.	Insurance	924,925,926		
24.	TOTAL FIXED COSTS (20 thru 23)			
25.	Less Plant Acquisition Adjustment	406		
26.	POWER COST (19 + 24 - 25)			

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USDA - REA

OPERATING REPORT - NUCLEAR PLANT

This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

BORROWER DESIGNATION	REA USE ONLY
Vermont 12 Hampshire	
PLANT	
Seabrook I (VT 12 .41259 share percent)	
YEAR ENDING	
December 31, 1993	

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

SECTION A. BOILERS AND GENERATING UNITS

LINE NO.	UNIT NO. (a)	TIMES STARTED (b)	SIZE (kW) (c)	GROSS GENERATION (MWh) (d)	OPERATING HOURS: IN SERVICE (e)	ON STANDBY (f)	OUT OF SERVICE: Scheduled (g)	Unscheduled (h)
1.	1		4 745					
2.								
3.								
4.								
5.								
6.	TOTAL							
7.	Station Service (MWh)							
8.	Net Generation (MWh)							
9.	Station Service % of Gross							

SECTION B. LABOR REPORT

LINE NO.	ITEM	VALUE	LINE NO.	ITEM	VALUE
1.	No. Emp. Full Time (inc. Superintendent)		5.	Maint. Plant Payroll ($)	
2.	No. Emp. Part Time		6.	Other Accounts Plant Payroll ($)	
3.	Total Emp.-Hrs. Worked		7.	TOTAL Plant Payroll ($)	
4.	Oper. Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

LINE NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Minute Gross Maximum Demand (kW)	
5.	Indicated Gross Maximum Demand (kW)	

*O&M costs in L1 Section D

SECTION D. COST OF NET ENERGY GENERATED

LINE NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)
1.	Operation, Supervision and Engineering	517	511 573	
2.	Fuel	518.1	315 905	
3.	Less Fuel Acquisition Adjustment	518.2		
4.	NET FUEL EXPENSE *(2 - 3)*		315 905	
5.	Coolants and Water	519	*	
6.	Steam Expenses	520	*	
7.	Steam From Other Sources	521	*	
8.	Electric Expenses	523	*	
9.	Miscellaneous Nuclear Power Expenses	524	*	
10.	Rents	525	*	
11.	OPERATION EXPENSES *(1 + 4 thru 10)*		827 478	
12.	Maintenance, Supervision and Engineering	528	*	
13.	Maintenance of Structures	529	*	
14.	Maintenance of Reactor Plant Equipment	530	*	
15.	Maintenance of Electric Plant	531	*	
16.	Maintenance of Miscellaneous Nuclear Plant	532	*	
17.	MAINTENANCE EXPENSES *(12 thru 16)*		*	
18.	Reactor Credits		*	
19.	TOTAL PRODUCTION EXPENSES *(11 + 17 - 18)*		* 827 478	
20.	Depreciation	403.2	757 164	
21.	Taxes	408	113 776	
22.	Interest	427	2069 304	
23.	Insurance	924,925,926	*	
24.	TOTAL FIXED COSTS *(20 thru 23)*		2940 244	
25.	Less Plant Acquisition Adjustment	406		
26.	POWER COST *(19 + 24 - 25)*		3767 722	

REA Form 12g *(Rev. 12-93)*

USDA - REA

OPERATING REPORT - NUCLEAR PLANT

This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

BORROWER DESIGNATION: Vermont 12 Hampshire

PLANT: Millstone 3 - Total Plant

YEAR ENDING: December 31, 1993

REA USE ONLY

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

SECTION A. BOILERS AND GENERATING UNITS

LINE NO.	UNIT NO. (a)	TIMES STARTED (b)	SIZE (kW) (c)	GROSS GENERATION (MWh) (d)	OPERATING HOURS: IN SERVICE (e)	ON STANDBY (f)	OUT OF SERVICE: Scheduled (g)	Unscheduled (h)
1.	1	4	1 253 000	6 849 406.5	6 106.6	169.2	2 199.8	284.4
2.								
3.								
4.								
5.								
6.	TOTAL		1 253 000	6 849 406.5				
7.	Station Service (MWh)			370 068.1				
8.	Net Generation (MWh)			6 520 454.8				
9.	Station Service % of Gross			5.4				

SECTION B. LABOR REPORT

LINE NO.	ITEM	VALUE	LINE NO.	ITEM	VALUE
1.	No. Emp. Full Time (inc. Superintendent)		5.	Maint. Plant Payroll ($)	
2.	No. Emp. Part Time		6.	Other Accounts Plant Payroll ($)	
3.	Total Emp.-Hrs. Worked		7.	TOTAL Plant Payroll ($)	
4.	Oper. Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

LINE NO.	ITEM	VALUE
1.	Load Factor (%)	66.0
2.	Plant Factor (%)	62.4
3.	Running Plant Capacity Factor (%)	89.5
4.	15 Minute Gross Maximum Demand (kW)	
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

LINE NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)
1.	Operation, Supervision and Engineering	517		
2.	Fuel	518.1		
3.	Less Fuel Acquisition Adjustment	518.2		
4.	NET FUEL EXPENSE *(2 - 3)*			
5.	Coolants and Water	519		
6.	Steam Expenses	520		
7.	Steam From Other Sources	521		
8.	Electric Expenses	523		
9.	Miscellaneous Nuclear Power Expenses	524		
10.	Rents	525		
11.	OPERATION EXPENSES *(1 + 4 thru 10)*			
12.	Maintenance, Supervision and Engineering	528		
13.	Maintenance of Structures	529		
14.	Maintenance of Reactor Plant Equipment	530		
15.	Maintenance of Electric Plant	531		
16.	Maintenance of Miscellaneous Nuclear Plant	532		
17.	MAINTENANCE EXPENSES *(12 thru 16)*			
18.	Reactor Credits			
19.	TOTAL PRODUCTION EXPENSES *(11 + 17 - 18)*			
20.	Depreciation	403.2		
21.	Taxes	408		
22.	Interest	427		
23.	Insurance	924,925,926		
24.	TOTAL FIXED COSTS *(20 thru 23)*			
25.	Less Plant Acquisition Adjustment	406		
26.	POWER COST *(19 + 24 - 25)*			

USDA - REA

OPERATING REPORT - NUCLEAR PLANT

This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

BORROWER DESIGNATION	REA USE ONLY
Vermont 12 Hampshire	
PLANT	
Millstone 3(VT-12 .35percent share)	
YEAR ENDING	
December 31, 1993	

SECTION A. BOILERS AND GENERATING UNITS

LINE NO.	UNIT NO. (a)	TIMES STARTED (b)	SIZE (kW) (c)	GROSS GENERATION (MWh) (d)	OPERATING HOURS IN SERVICE (e)	ON STANDBY (f)	OUT OF SERVICE Scheduled (g)	OUT OF SERVICE Unscheduled (h)
1.	1	4	4 386	23 972.9	6 106.6	169.2	2 199.8	284.4
2.								
3.								
4.								
5.								
6.	TOTAL			23 972.9				
7.	Station Service (MWh)			1 295.2				
8.	Net Generation (MWh)			22 821.6				
9.	Station Service % of Gross			5.4				

SECTION B. LABOR REPORT

LINE NO.	ITEM	VALUE	LINE NO.	ITEM	VALUE
1.	No. Emp. Full Time (inc. Superintendent)		5.	Maint. Plant Payroll ($)	
2.	No. Emp. Part Time		6.	Other Accounts Plant Payroll ($)	
3.	Total Emp.-Hrs. Worked		7.	TOTAL Plant Payroll ($)	
4.	Oper. Plant Payroll ($)				

SECTION C. FACTORS & MAXIMUM DEMAND

LINE NO.	ITEM	VALUE
1.	Load Factor (%)	
2.	Plant Factor (%)	
3.	Running Plant Capacity Factor (%)	
4.	15 Minute Gross Maximum Demand (kW)	
5.	Indicated Gross Maximum Demand (kW)	

*O&M costs Section D L1

SECTION D. COST OF NET ENERGY GENERATED

LINE NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)
1.	Operation, Supervision and Engineering	517	593 870	
2.	Fuel	518.1	113 536	4.97
3.	Less Fuel Acquisition Adjustment	518.2	(99 000)	4.34
4.	NET FUEL EXPENSE (2 - 3)		14 536	0.63
5.	Coolants and Water	519	*	
6.	Steam Expenses	520	*	
7.	Steam From Other Sources	521	*	
8.	Electric Expenses	523	*	
9.	Miscellaneous Nuclear Power Expenses	524	651	
10.	Rents	525	*	
11.	OPERATION EXPENSES (1 + 4 thru 10)		609 057	26.69
12.	Maintenance, Supervision and Engineering	528	*	
13.	Maintenance of Structures	529	*	
14.	Maintenance of Reactor Plant Equipment	530	*	
15.	Maintenance of Electric Plant	531	*	
16.	Maintenance of Miscellaneous Nuclear Plant	532	*	
17.	MAINTENANCE EXPENSES (12 thru 16)		*	
18.	Reactor Credits		*	
19.	TOTAL PRODUCTION EXPENSES (11 + 17 - 18)		609 057	26.69
20.	Depreciation	403.2	423 368	
21.	Taxes	408	92 662	
22.	Interest	427	1605 470	
23.	Insurance	924,925,928	*	
24.	TOTAL FIXED COSTS (20 thru 23)		2121 500	92.96
25.	Less Plant Acquisition Adjustment	406		
26.	POWER COST (19 + 24 - 25)		2730 557	119.65

USDA - REA

OPERATING REPORT - ANNUAL SUPPLEMENT

This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.

INSTRUCTIONS - *Submit an original and two copies to REA. For detailed instructions, see REA Bulletin 1717B-3.*

BORROWER DESIGNATION: Vermont 12 Hampshire

YEAR ENDING: December 31, 1993

REA USE ONLY

SECTION A. UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1. Total Intangible Plant *(301 thru 303)*	19 667				19 667
2. Total Steam Production Plant *(310 thru 316)*					
3. Total Nuclear Production Plant *(320 thru 325)*					
4. Total Hydro Production Plant *(330 thru 336)*	9 800				9 800
5. Total Other Production Plant *(340 thru 346)*					
6. Total Production Plant *(2 thru 5)*	9 800				9 800
7. Land and Land Rights *(350)*	16 440				16 440
8. Structures and Improvements *(352)*	57 565				57 565
9. Station Equipment *(353)*	653 811				653 811
10. Other Transmission Plant *(354 thru 359)*	48 605				48 605
11. Total Transmission Plant *(7 thru 10)*	776 421				776 421
12. Land and Land Rights *(360)*					
13. Structures and Improvements *(361)*					
14. Station Equipment *(362)*					
15. Other Distribution Plant *(363 thru 373)*					
16. Total Distribution Plant *(12 thru 15)*					
17. Total General Plant *(389 thru 399)*	195				195
18. Electric Plant in Service *(1 + 6 + 11 + 16 + 17)*	806 083				806 083
19. Electric Plant Purchased or Sold *(102)*					
20. Electric Plant Leased to Others *(104)*					
21. Electric Plant Held for Future Use *(105)*					
22. Completed Construction Not Classified *(106)*	55 685 039	155 606			55 840 645
23. Acquisition Adjustments *(114)*					
24. Other Utility Plant *(118)*					
25. Nuclear Fuel Assemblies *(120.1 thru 120.4)*	2 399 316	256 620			2 655 936
26. Total Utility Plant in Service *(18 thru 25)*	58 890 438	412 226			59 302 664
27. Construction Work in Progress *(107)*					
28. Total Utility Plant *(26 + 27)*	58 890 438	412 226			59 302 664

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT

ITEM	COMPOSITE RATE (%) (a)	BALANCE BEGINNING OF YEAR (b)	ANNUAL ACCRUALS (c)	RETIREMENTS LESS NET SALVAGE (d)	ADJUSTMENTS AND TRANSFERS (e)	BALANCE END OF YEAR (f)
1. Depr. of Steam Prod. Plant *(108.1)*						
2. Depr. of Nuclear Prod. Plant *(108.2)*	2.86	4 503 147	1 127 768			5 630 915
3. Depr. of Hydraulic Prod. Plant *(108.3)*	2	2 373 363	320 004			2 693 367
4. Depr. of Other Prod. Plant *(108.4)*						
5. Depr. of Transmission Plant *(108.5)*		663 245	96 183			759 428
6. Depr. of Distribution Plant *(108.6)*						
7. Depr. of General Plant *(108.7)*						
8. Retirement Work in Progress *(108.8)*						
9. Total Depr. for Elec. Plant in Serv. *(1 - 8)*		7 539 755				9 083 710
10. Depr. of Plant Leased to Others *(109)*						
11. Depr. of Plant Held for Future Use *(110)*						
12. Amort. of Elec. Plant in Service *(111)*						
13. Amort. of Leased Plant *(112)*						
14. Amort. of Plant Held for Future *(113)*						
15. Amort. of Acquisition Adj. *(115)*						
16. Depr. & Amort. Other Plant *(119)*						
17. Amort. of Nuclear Fuel *(120.5)*		1 565 282	373 051			1 938 338
18. Total Prov. for Depr. & Amort. *(9 - 17)*		9 105 042	1 917 006			11 022 048

VERMONT 12 HAMPSHIRE
DECEMBER 31, 1993

REA FORM 12 H SECTION A. LINE 22

ANALYSIS OF COMPLETED CONSTRUCTION NOT CLASSIFIED

ACCOUNT #	SEABROOK NCLR PLANT	MILLSTONE 3 NCLR PLANT	N HARTLAND HYDRO PLANT	SEVERAL TRANSM. PLANTS		TOTAL
106.21				692,531		692,531
106.23				35,788		35,788
106.24				250,457		250,457
106.25				8,928		8,928
106.31			15,332,049			15,332,049
106.33		13,384,260				13,384,260
106.34	24,898,606					24,898,606
106.39			0			0
106.63		377,681				377,681
106.64	860,345					860,345
TOTALS	25,758,952	13,761,940	15,332,049	987,705	0	55,840,645
	25,700,000	13,800,000	15,300,000	1,000,000		55,800,000

USDA - REA OPERATING REPORT - ANNUAL SUPPLEMENT	BORROWER DESIGNATI. Vermont 12 Hampshire YEAR ENDING December 31, 19 93	REA USE ONLY

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT (Continued)

19. Amount of Annual Accrual Charged to Expense $ 1 917 006	20. Amount of Annual Accrual Charged to Other Accounts $ 207 919	21. Book Cost of Property Retired $ N/A
22. Removal Cost of Property Retired $ N/A	23. Salvage Material from Property Retired $ N/A	24. Renewal and Replacement Cost $ N/A

SECTION C. NONUTILITY PROPERTY Intentionally Blank

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1. NONUTILITY PROPERTY (121)					
2. PROVISION FOR DEPR. & AMORT. (122)					

SECTION D. DEMAND AND ENERGY AT POWER SOURCES

MONTH	MONTHLY PEAKS					ENERGY OUTPUT (MWh) (f)	LOAD FACTOR (%) (g)
	PEAK DEMAND (MW) (a)	DAY OF WEEK (b)	DAY OF MONTH (c)	HOUR OF DAY (d)	TYPE OF READING (e)		
1. JANUARY	37.2					13 348.7	48.2
2. FEBRUARY	37.2					13 676.0	49.4
3. MARCH	37.2					12765.5	49.3
4. APRIL	37.2					14 251.8	51.5
5. MAY	32.7					12 233.1	45.7
6. JUNE	32.7					13 574.0	55.8
7. JULY	32.7					12 709.1	54.0
8. AUGUST	32.7					13 431.6	55.2
9. SEPTEMBER	32.7					11 743.8	48.3
10. OCTOBER	31.2					8 016.9	35.7
11. NOVEMBER	31.2					10 299.6	44.3
12. DECEMBER	30.2					12 907.8	59.4
13. ANNUAL PEAK					ANNUAL TOTAL	148 957.9	49.7

REMARKS

SECTION E. DEMAND AND ENERGY AT DELIVERY POINTS

MONTH	DELIVERED TO REA BORROWERS			DELIVERED TO OTHERS		TOTAL DELIVERED		
	DEMAND (MW) (a)	ENERGY (MWh) (b)	LOAD FACT. (%) (c)	DEMAND (MW) (d)	ENERGY (MWh) (e)	DEMAND (MW) (f)	ENERGY (MWh) (g)	LOAD FACT. (%) (h)
1. JANUARY	33.2	9 771.0	39.6	4	2 688.1	37.2	12 459.1	45.0
2. FEBRUARY	33.2	10 020.3	40.6	4	2 693.2	37.2	12 713.5	45.9
3. MARCH	33.2	9 338.0	40.4	4	2 655.5	37.2	11 993.6	46.3
4. APRIL	32.2	9 788.8	40.9	5	3 631.5	37.2	13 432.3	48.5
5. MAY	27.2	6 059.6	31.0	10	5 444.9	37.2	11 504.5	43.0
6. JUNE	22.7	5 824.7	34.5	10	7 012.2	32.7	12 836.9	52.8
7. JULY	23.7	5 678.9	33.3	9	6 423.1	32.7	12 102.0	51.4
8. AUGUST	23.7	6 571.7	37.3	9	6 161.7	32.7	12 733.[illegible]	52.3
9. SEPTEMBER	26.7	6 841.0	34.4	6	4 115.9	32.7	10 956.8	45.0
10. OCTOBER	29.2	6 317.5	30.1	2	1 019.2	31.2	7 336.7	32.7
11. NOVEMBER	27.2	7 399.3	29.1	4	2 246.2	31.2	9 645.5	41.6
12. DECEMBER	24.2	8 723.5	50.1	6	3 479.0	30.2	12 202.4	56.1
13. PEAK OR TOTAL		92 334.3	37.5		47 570.3		139 904.6	42.9

REMARKS

USDA REA	BORROWER DESIGNATION	
OPERATNG REPORT - ANNUAL SUPPLEMENT	Vermont 12 Hampshire	
	PERIOD ENDED: December 31, 1993	REA USE ONLY

INSTRUCTIONS - Reporting of Investments is required by 7 CFR 1717, Subpart N. Identify investments primarily for Rural Development with "RD" in column (e).

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS - POWER SUPPLY

PART I. INVESTMENTS

DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
1. NON UTILITY PROPERTY (NET)				
a. Intentionally Blank				
b.				
c.				
d.				
e. Totals				
2. INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
a. N.R.U.C.F.C. - CTC		17 167	858	
b. N.R.U.C.F.C. - membership		1 000		
c. National Bank for Cooperatives - E Stock		1 000		
d. N.R.E.C.A. - membership	10			
e. Totals	10	19 167	858	
3. INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
a. Intentionally Blank				
b.				
c.				
d.				
e. Totals				
4. OTHER INVESTMENTS				
a. V.E.L.C.O. stock - Phase 1	152 464	-		
b.				
c.				
d.				
e. Totals	152 464			
5. SPECIAL FUNDS				
a. Intentionally Blank				
b.				
c.				
d.				
e. Totals				
6. CASH - GENERAL				
a. General Fund	500			
b.				
c.				
d.				
e. Totals				
7. SPECIAL DEPOSITS				
a. Intentionally Blank				
b.				
c.				
d.				
e. Totals				

USDA-REA	BORROWER DESIGNATION Vermont 12 Hampshire	
OPERATING REPORT - ANNUAL SUPPLEMENT	YEAR ENDED December 31, 1993	REA USE ONLY

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS - POWER SUPPLY *(Continued)*

PART I. INVESTMENTS *(Continued)*

DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS ($) (d)	RD (e)
8. TEMPORARY INVESTMENTS				
a. Intentionally Blank				
b.				
c.				
d.				
e. Totals				
9. ACCOUNTS & NOTES RECEIVABLE (NET)				
a. Energy Account (VERMONT 7)		44 591 449		
b. A/R Misc. Power	45 982			
c. A/R Intercompany Services	4 205			
d. A/R Staff Advance	100			
e. Totals	50 287	44 591 449		
10. COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED Intentionally Blank				
a.				
b.				
c.				
d.				
e. Totals				
11. TOTAL OF INVESTMENTS *(1 thru 10)*	203 261	44 610 616		

PART II. LOAN GUARANTEES Intentionally Blank

ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RD (e)
1.				
2.				
3.				
4. TOTALS				
5. TOTALS *(Include Loan Guarantees Only)*				

PART III. RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT *[Total of Included Investments (Part I, 11b) and Loan Guarantees - Loan Balance (Part II, 5d) to Total Utility Plant (Form 12a, Section B, Line 3)]*	0.34 %

PART IV. LOANS Intentionally Blank

ORGANIZATION (a)	MATURITY DATE (b)	ORIGINAL AMOUNT ($) (c)	LOAN BALANCE ($) (d)	RD (e)
1. Employees, Officers, Directors				
2. Energy Resource Conservation Loans				
3.				
4.				
5.				
6.				
7. TOTALS				

USDA-REA

OPERATING REPORT - ANNUAL SUPPLEMENT

INSTRUCTIONS - See REA Bulletin 1717B-3

BORROWER DESIGNATION: Vermont 12 Hampshire

PERIOD ENDED: December 31, 1993

REA USE ONLY

SECTION G. MATERIALS AND SUPPLIES INVENTORY Intentionally Blank

ITEM	BALANCE BEGINNING OF YEAR (a)	PURCHASED & SALVAGED (b)	USED & SOLD (c)	BALANCE END OF YEAR (d)
1. Coal				
2. Other Fuel				
3. Production Plant Parts and Supplies				
4. Station Transformers and Equipment				
5. Line Materials and Supplies				
6. Other Materials and Supplies				
7. TOTAL (Sum of lines 1 thru 6)				

SECTION H. LONG-TERM DEBT AND DEBT SERVICE REQUIREMENTS

ITEM	BALANCE END OF YEAR (a)	BILLED THIS YEAR INTEREST (b)	PRINCIPAL (c)	TOTAL (d)	REA USE ONLY (e)
1. Rural Electrification Administration (Exclude REA - Econ. Dev. Loans)	14 446 119	722 306	222 904	945 210	
2. National Rural Utilities Cooperative Finance Corporation					
3. Bank for Cooperatives	10 919 776	1 782 728	224 921	2 007 649	
4. Federal Financing Bank	10 919 776	1 782 728	224 921	2 007 649	
5. REA - Economic Development Loans					
6. Other National Bank for Cooperatives	16 789 272	519 707	62 882	582 589	
7.					
8.					
9. TOTAL (Sum of 1 thru 8)	42 155 167	3 024 741	510 707	3 535 448	

SECTION I. ANNUAL MEETING AND BOARD DATA

1. Date of Last Annual Meeting: May 5, 1993	2. Total Number of Eligible Voters: 6	3. Was Quorum Present? ☒ Yes ☐ No	4. Number of Members Voting by Proxy or Mail: 0
5. Number of Members Present at Meeting: 3	6. Total Number of Board Members: 6	7. Annual Cost of Directors' Fees and Expenses: $ 7,406	8. Does Manager Have Written Contract? ☒ Yes ☐ No

SECTION J. MAN-HOUR AND PAYROLL STATISTICS Intentionally Blank

1. Number of Full Time Employees		4. Payroll Expensed	
2. Man-Hours Worked - Regular Time		5. Payroll Capitalized	
3. Man-Hours Worked - Overtime		6. Payroll Other	

SECTION K. LONG TERM LEASES (If additional space is needed, use separate sheet.) Intentionally Blank

LIST BELOW ALL RESTRICTED PROPERTY * HELD UNDER LONG TERM ** LEASE (If NONE, state NONE)

NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.		
2.		
3.		
4. TOTAL		

* "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, trailers, tractors, other vehicles (including without limitation aircraft and ships), office, garage and warehouse space and office equipment (and without limitation computers).

** "LONG-TERM" means leases having unexpired terms of more than 12 months (taking into account terms of rental at the option of the lessor, whether or not such leases have been renewed).

SECTION L. NOTES

IF ADDITIONAL SPACE IS NEEDED, USE SEPARATE SHEET

USDA - REA OPERATING REPORT - LINES AND STATIONS	*This data will be used to determine your operating results and financial situation. Your response is required (7 U.S.C. 901 et seq.) and is not confidential.*	
	BORROWER DESIGNATION Vermont 12 Hampshire	REA USE ONLY
INSTRUCTIONS - *Submit an original and two copies to REA. For details, see REA Bulletin 1717B-3.*	YEAR ENDING December 31, 1993	

SECTION A. EXPENSE AND COSTS

ITEMS	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
TRANSMISSION OPERATION			
1. SUPERVISION AND ENGINEERING	560	21 952	
2. LOAD DISPATCHING	561		
3. STATION EXPENSES	562		
4. OVERHEAD LINE EXPENSES	563		
5. UNDERGROUND LINE EXPENSES	564		
6. MISCELLANEOUS EXPENSES	566	216	
7. SUBTOTAL *(1 thru 6)*		22 168	
8. TRANSMISSION OF ELECTRICITY BY OTHERS	565	597 939	
9. RENTS	567		
10. TOTAL TRANSMISSION OPERATION *(7 thru 9)*		620 107	
TRANSMISSION MAINTENANCE			
11. SUPERVISION AND ENGINEERING	568		
12. STRUCTURES	569		
13. STATION EQUIPMENT	570		
14. OVERHEAD LINES	571		
15. UNDERGROUND LINES	572		
16. MISCELLANEOUS TRANSMISSION PLANT	573		
17. TOTAL TRANSMISSION MAINTENANCE *(11 thru 16)*			
18. TOTAL TRANSMISSION EXPENSE *(10 + 17)*			
19. DISTRIBUTION EXPENSE — OPERATION	580 thru 589		
20. DISTRIBUTION EXPENSE — MAINTENANCE	590 thru 598		
21. TOTAL DISTRIBUTION EXPENSE *(19 + 20)*			
22. TOTAL OPERATION AND MAINTENANCE *(18 + 21)*			
FIXED COSTS			
23. DEPRECIATION — TRANSMISSION	403.5	96 183	
24. DEPRECIATION — DISTRIBUTION	403.6		
25. TAXES — TRANSMISSION	408		
26. TAXES — DISTRIBUTION	408		
27. INTEREST — TRANSMISSION	427	129 878	
28. INTEREST — DISTRIBUTION	427		
29. INSURANCE — TRANSMISSION	924, 925, 926		
30. INSURANCE — DISTRIBUTION	924, 925, 926		
31. TOTAL TRANSMISSION *(18 + 23 + 25 + 27 + 29)*		846 168	
32. TOTAL DISTRIBUTION *(21 + 24 + 26 + 28 + 30)*			
33. TOTAL LINES AND STATIONS *(31 + 32)*		846 168	

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS N/A	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1. 7.2/12.5	1.0	9. STEPUP AT GENERATING PLANTS	
2. 115 2.68% 7.6	.2		
3.		10. TRANSMISSION	
4.			
5.		11. DISTRIBUTION	
6. TOTAL *(1 thru 5)*	1.2		
7. DISTR. LINES	—	12. TOTAL *(9 thru 11)*	
8. TOTAL *(6 + 7)*	1.2		

SECTION C. LABOR AND MATERIAL SUMMARY

1. NUMBER OF EMPLOYEES N/A

ITEM	LINES	STATIONS
2. OPER. LABOR		
3. MAINT. LABOR		
4. OPER. MATERIAL		
5. MAINT. MATERIAL		

SECTION D. OUTAGES N/A

1. TOTAL	
2. AVG. NO. DISTR. CONS. SERVED	
3. AVG. NO. HOURS OUT PER CONS.	

A7-1-10

The Commonwealth of Massachusetts

RETURN

OF THE

TOWN OF

HUDSON, LIGHT AND POWER DEPARTMENT

TO THE

DEPARTMENT OF PUBLIC UTILITIES

OF MASSACHUSETTS

For the Year Ended December 31, 1993

1993

Name of officer to whom correpondence should be addressed regarding this report. Horst Huehmer

Official title Manager

Official Address 49 Forest Avenue
Hudson, MA 01749

Form AC-19

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PAGES INTENTIONALLY OMITTED: 23 TO 36 AND 53 TO 56

GENERAL INFORMATION

1 **Name of town (or city) making this report.**

Hudson, Ma 01749

2 **If the town (or city) has acquired a plant,**

Kind of plant, whether gas or electric. Electric

Owner from whom purchased, if so acquired. Hudson Electric Co. 7/11/1891

Date of votes to acquire a plant in accordance with the provisions of chapter 164 of the General Laws. 9/11/1891

Record of votes: First vote: yes, 30; No, 7 Second vote: Yes, 69; No, 11

Date when town (or city) began to sell gas and electricity January 15, 1897

3 **Name and address of manager of municipal lighting:**

Horst Huehmer
23 Plant Avenue
Hudson, MA 01749

4 **Name and address of mayor or selectmen:**

Richard G. Beauregard	Joseph J. Durant	Joann P. Forance	Carl J. Leeber	Robert J. Steere
40 Green Street	22 Harriman Road	7 Kathleen Road	4 Lark Drive	35 Old Bolton Road
Hudson, MA 01749	Hudson, MA 01749	Hudson, MA 01749	Hudson, MA 01749	Hudson, MA 01749

5 **Name and address of town (or city) treasurer:**

Virginia Cahill
5 Rockport Road
Southboro, MA 01772

6 **Name and address of town (or city) clerk:**

Dorothy A. Risser
3 Lincoln Street
Hudson, MA 01749

7 **Name and addresses of members of municipal light board:**

Roland L. Plante	Peter R. Keane	Weedon G. Parris, Jr.
136 Murphy Street	15 John Robinson Road	9 Champlain Drive
Hudson, MA 01749	Hudson, Ma 01749	Hudson, MA 01749

8 **Total valuation of estates in town (or city) according to the last State valuation** $944,454,497.00

9 **Tax rate for all purposes during the year:** $15.04 Res
$26.39 Com

10 **Amount of manager's salary:** 93,800.79

11 **Amount of manager's bond:** $1,000.00

12 **Amount of salary paid to members of municipal light board (each):** $500.00

FURNISH SCHEDULE OF ESTIMATES REQUIRED BY GENERAL LAWS, CHAPTER 164, SECTION 57 FOR GAS AND ELECTRIC LIGHT PLANTS FOR THE FISCAL YEAR, ENDING DECEMBER 31, NEXT.

			Amount
	INCOME FROM PRIVATE CONSUMERS:		
1	From sales of gas		
2	From sales of electricity		$27,658,009.00
3			
4		**TOTAL**	$27,658,009.00
5	**EXPENSES:**		
6	For operation, maintenance and repairs		$26,873,452.00
7	For interest on bonds, notes of scrip		$0.00
8	For depreciation fund (3 per cent. on $18669168.74 as per page 9)		$560,075.06
9	For sinking fund requirements		$0.00
10	For note payments		$0.00
11	For bond payments		$0.00
12	For loss in preceding year		$0.00
13			
14		**TOTAL**	$27,433,527.06
15	**COST:**		
16	Of gas to be used for municipal buildings		$0.00
17	Of gas to be used for street lights		$0.00
18	Of electricity to be used for municipal buildings		$612,700.00
19	Of electricity to be used for street lights		$118,700.00
20	Total of the above items to be included in the tax levy		$731,400.00
21			
22	New construction to be included in the tax levy		0
23	Total amounts to be included in the tax levy		$731,400.00

CUSTOMER

Names of the cities or towns in which the plant supplies GAS, with the number of customers' meters in each.		Names of the cities or towns in which the plant supplies ELECTRICITY, with the number of customers' meters in each	
City or Town	**Number of Customers Meters, Dec. 31**	**City or Town**	**Number of Customers Meters, Dec. 31**
		Hudson	7,621
		Stow	2,315
		Berlin, Bolton, Boxboro	
		Harvard, Maynard	
		Marlboro	110
TOTAL		**TOTAL**	10,046

APPROPRIATIONS SINCE BEGINNING OF YEAR

(Includes also all items charge direct to tax levy, even where no appropriation is made or required.)

FOR CONSTRUCTION OR PURCHASE OF PLANT:

*At	meeting	19	, to be paid from ~	
*At	meeting	19	, to be paid from ~	
			TOTAL	None

FOR THE ESTIMATED COST OF THE HAS OR ELECTRICITY TO BE USED BY THE CITY OR TOWN FOR:

1	Street lights	$137,132.00
2	Municipal buildings (Amounts are included in overall appropriations for each Department)	
3		
	TOTAL	$137,132.00

*Date of meeting and whether regular or special. ~Here insert bonds, notes or tax levy.

CHANGES IN PROPERTY

1 Describe briefly all the important physical changes in the property during the last fiscal period including additions, alterations or improvements to the works or physical property retired.

In electric property:

Expanded 115KV Substation at Forest Ave.

In gas property:

NOT APPLICABLE

BONDS

(Issued on Account of Gas or Electric Lighting.)

When Authorized*	Date of Issue	Amount of Original Issues**	Period of Payments		Interest		Amount Outstanding at End of Year
			Amounts	When Payable	Rate	When Payable	
Apr. 7, 1913	Spec. Jun. 1, 1913	$9,000.00					
Mar. 4, 1918	Reg. Apr. 1, 1918	$50,000.00					
Jun. 14, 1920	Spec. Feb. 1, 1921	$25,000.00					
Mar. 5, 1928	Reg. Nov. 1, 1928	$40,000.00					
Nov. 29, 1954	Spec. Mar. 1, 1955	$250,000.00					
Mar. 7, 1955	Spec. May 1, 1955	$100,000.00					
Mar. 7, 1955	Reg. Nov. 1, 1955	$150,000.00					
Jun. 8, 1959	Spec. Aug. 1, 1959	$300,000.00					
Nov. 7, 1961	Spec. Jul. 15, 1962	$450,000.00					
	TOTAL	$1,374,000.00				TOTAL	

The bonds and notes outstanding at the end of year should agree with the Balance Sheet. When bonds and notes are repaid report the first three columns only.

*Date of meeting and whether regular or special. **List original issue of bonds and nores including those that have been retired.

TOWN NOTES
(Issued on Account of Gas or Electric Lighting.)

When Authorized*	Date of Issue	Amount of Original Issues**	Period of Payments		Interest		Amount Outstanding at End of Year
			Amounts	When Payable	Rate	When Payable	
Dec. 18,1896. Spec.	Jan. 1, 1897	$18,000.00					
June 20, 1897. Spec.	Jan. 1, 1898	$17,000.00					
June 10, 1898. Spec.	Jul. 1, 1898	$5,000.00					
Nov. 5, 1903. Spec.	Nov. 2, 1903	$13,000.00					
Mar. 7, 1904. Reg.	Jan. 1, 1905	$5,000.00					
Apr. 2, 1912. Spec.	May 1, 1912	$2,000.00					
Aug. 4, 1941. Spec.	Oct. 15, 1941	$100,000.00					
Sep. 14, 1942. Spec.	Oct. 15, 1942	$100,000.00					
Feb. 8, 1943. Spec.	Feb. 15, 1943	$50,000.00					
Mar. 6, 1950. Reg.	Sep. 15, 1950	$241,000.00					
	TOTAL	$551,000.00				TOTAL	

The bonds and notes outstanding at the end of year should agree with the Balance Sheet. When bonds and notes are repaid report the first three columns only.

* Date of meeting and whether regular or special. ** List original issues of bonds and notes including those that have been retired.

TOTAL COST OF PLANT - ELECTRIC

1. Report below the cost of utility plant in service according to prescribed accounts.
2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.
3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.
4. Reclassifications or transfers within utility plant accounts should be shown in column (f).

Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1. INTANGIBLE PLANT	$3,879.76	$0.00	$0.00	$0.00	$0.00	$3,879.76
	$3,879.76	$0.00	$0.00	$0.00	$0.00	$3,879.76
2. PRODUCTION PLANT						
A. Steam Production						
310 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
311 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
312 Boiler Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
313 Engines and Engine Driven Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
314 Turbogenerator Unites	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
315 Accessory Electric equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
316 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Steam Production Plant	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
B. Nuclear Production Plant						
320 Land and Land rights	$1,252.93	$0.00	$0.00	$0.00	$0.00	$1,252.93
321 Structures and Improvements	$847,640.09	$116.54	$0.00	$0.00	$0.00	$847,756.63
322 Reactor Plant equipment	$1,252,311.84	$3,542.72	$0.00	$0.00	$0.00	$1,255,854.56
323 Turbogenerator Units	$203,948.74	($676.30)	$0.00	$0.00	$0.00	$203,272.44
324 Accessory electric equipment	$304,207.65	$190.61	$0.00	$0.00	$0.00	$304,398.26
325 Miscellaneous Power Plant						$0.00
Equipment	$96,711.21	($1,305.70)	$0.00	$0.00	$0.00	$95,405.51
Total Nuclear Production Plant	$2,706,072.46	$1,867.87	$0.00	$0.00	$0.00	$2,707,940.33

TOTAL COST OF PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	**C. Hydraulic Production Plant**						
2	330 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	331 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	332 Reservoirs, Dams and Waterways	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	333 Water Wheels, Turbines and Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	334 Accessory Electric Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	335 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	336 Roads, Railroads and Bridges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	**D. Other Production Plant**						
10	340 Land and Land Rights	$5,500.00	$0.00	$0.00	$0.00	$0.00	$5,500.00
11	341 Structures and Improvements	$332,767.70	$1,503.06	$0.00	$0.00	$0.00	$334,270.76
12	342 Fuel Holders, Producers and Accessories	$123,989.32	$0.00	$0.00	$0.00	$0.00	$123,989.32
13	343 Prime Mowers	$2,455,596.22	$0.00	$0.00	$0.00	$0.00	$2,455,596.22
14	344 Generators	$296,559.88	$0.00	$0.00	$0.00	$0.00	$296,559.88
15	345 Accessory Electric Equipment	$832,470.28	$0.00	$0.00	$0.00	$0.00	$832,470.28
16	346 Miscellaneous Power Plant Equipment	$43,463.17	$76,117.53	$0.00	$0.00	$0.00	$119,580.70
17	**Total Other Production Plant**	$4,090,346.57	$77,620.59	$0.00	$0.00	$0.00	$4,167,967.16
18	**Total Production Plant**	$6,796,419.03	$79,488.46	$0.00	$0.00	$0.00	$6,875,907.49
19	**3. TRANSMISSION PLANT**						
20	350 Land and Land Rights	$53,804.14	$0.00	$0.00	$0.00	$0.00	$53,804.14
21	351 Clearing Land and Rights of Way	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
22	352 Structures and Improvements	$168,166.08	$0.00	$0.00	$0.00	$0.00	$168,166.08
23	353 Station Equipment	$385,601.70	$11,061.35	$0.00	$0.00	$0.00	$396,663.05
24	354 Towers and Fixtures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
25	355 Poles and Fixtures	$796,839.02	$0.00	$0.00	$0.00	$0.00	$796,839.02
26	356 Overhead Conductors and Devices	$227,329.01	$0.00	$0.00	$0.00	$0.00	$227,329.01
27	357 Underground Conduit	$258.07	$0.00	$0.00	$0.00	$0.00	$258.07
28	358 Underground Conductors and Devices	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
29	359 Roads and Trails	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	**Total Transmission Plant**	$1,631,998.02	$11,061.35	$0.00	$0.00	$0.00	$1,643,059.37

TOTAL COST OF PLANT (Concluded)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	**4. DISTRIBUTION PLANT**						
2	360 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	361 Structures and Improvements	$9,286.53	$0.00	$0.00	$0.00	$0.00	$9,286.53
4	362 Station Equipment	$474,378.93	$1,366,997.14	$0.00	$0.00	$0.00	$1,841,376.07
5	363 Storage Battery Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	364 Poles, Towers and Fixtures	$734,309.75	$31,049.76	$0.00	$0.00	$0.00	$765,359.51
7	365 Overhead Conductors and Devices	$2,175,334.51	($125,315.57)	$0.00	($330,382.64)	$0.00	$1,719,636.30
8	366 Underground Conduit	$286,774.90	$117,572.98	$0.00	$0.00	$0.00	$404,347.88
9	367 Underground Conductors & Devices	$675,195.61	$131,962.81	$0.00	($328,364.61)	$0.00	$478,793.81
10	368 Line Transformers	$1,863,977.53	$126,617.20	$2,728.63	$0.00	$0.00	$1,987,866.10
11	369 Services	$479,242.37	$33,563.94	$0.00	($93,721.61)	$0.00	$419,084.70
12	370 Meters	$652,790.55	$16,750.46	$4,009.01	$0.00	$0.00	$665,532.00
13	371 Installations on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	372 Leased Prop. on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	373 Street Lighting and Signal Systems	$345,031.88	$26,571.80	$0.00	($42,578.02)	$0.00	$329,025.66
16	**Total Distribution Plant . . . .**	$7,696,322.56	$1,725,770.52	$6,737.64	($795,046.88)	$0.00	$8,620,308.56
17	**5. GENERAL PLANT**						
18	389 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
19	390 Structures and Improvements	$474,165.26	$17.00	$0.00	$0.00	$0.00	$474,182.26
20	391 Office Furniture and Equipment	$464,211.79	$26,341.46	$0.00	$0.00	$0.00	$490,553.25
21	392 Transportation Equipment	$513,104.70	$0.00	$10,700.00	$0.00	$0.00	$502,404.70
22	393 Stores Equipment	$12,045.77	$0.00	$0.00	$0.00	$0.00	$12,045.77
23	394 Tools, Shop and Garage Equipment	$16,224.04	$0.00	$0.00	$0.00	$0.00	$16,224.04
24	395 Laboratory Equipment	$20,609.03	$11,190.19	$0.00	$0.00	$0.00	$31,799.22
25	396 Power Operated Equipment	$3,497.53	$0.00	$0.00	$0.00	$0.00	$3,497.53
26	397 Communication Equipment	$45,198.76	$55.68	$0.00	$0.00	$0.00	$45,254.44
27	398 Miscellaneous Equipment	$14,411.60	$43.86	$0.00	$0.00	$0.00	$14,455.46
28	399 Other Tangible Property	$33.72	$0.00	$0.00	$0.00	$0.00	$33.72
29	**Total General Plant . . . .**	$1,563,502.20	$37,648.19	$10,700.00	$0.00	$0.00	$1,590,450.39
30	**Total Electric Plant in Service**	$17,692,121.57	$1,853,968.52	$17,437.64	($795,046.88)	$0.00	$18,733,605.57
31							
32					**Total Cost of Electric Plant . . . . .**		$18,733,605.57
33							
34					**Less Cost of Land, Land Rights, Rights of Way . .**		$64,436.83
					Total Cost upon which Depreciation is based . . .		$18,669,168.74

The above figures should show the original cost of the existing property. In case any part of property is sold or retired, the cost of such property should be deducted from the cost of plant. The act cost of the property, less the land values, should be taken as a basis for figuring depreciation.

COMPARATIVE BALANCE SHEET Assets and Other Debits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	**UTILITY PLANT**			
2	101 Utility Plant - Electric (P.17)	6,169,625.74	6,696,026.84	526,401.10
3	101 Utility Plant - Gas (P.20)	0.00	0.00	0.00
4	120 Nuclear Fuel	74,984.43	69,399.38	(5,585.05)
5	Total Utility Plant	6,244,610.17	6,765,426.22	520,816.05
6	**OTHER PROPERTY & INVESTMENTS**			
7	123 Invest in Assoc. Companies	146,418.33	146,418.33	0.00
8	124 Other Investments	0.00	0.00	
9	Total Other Prop. & Investment	146,418.33	146,418.33	0.00
10				0.00
11	**FUND ACCOUNTS**			0.00
12	125 Sinking Funds	0.00	0.00	0.00
13	126 Depreciation Fund (P. 14)	3,004,137.73	1,866,445.86	(1,137,691.87)
14	128 Other Special Funds	3,177,903.74	5,671,310.49	2,493,406.75
15	Total Funds	6,182,041.47	7,537,756.35	1,355,714.88
16	**CURRENT AND ACCRUED ASSETS**			
17	131 Cash (P. 14)	2,405,039.77	2,749,139.97	344,100.20
18	132 Special Deposits	335,620.30	358,871.67	23,251.37
19	135 Working Funds	500.00	500.00	0.00
20	142 Customer Accounts Receivable	2,840,111.20	2,964,220.40	124,109.20
21	143 Other Accounts Receivable	112,207.61	39,235.88	(72,971.73)
22	146 Receivables from Municipality	2,286.36	2,286.36	0.00
23	151 Materials and Supplies (P.14)	563,699.03	1,091,409.09	527,710.06
24	165 Prepayments	424,584.79	419,012.69	(5,572.10)
25	171 Dividend & Int. Receivable	31,278.09	45,771.61	14,493.52
26	173 Accrued Utility Revenues	0.00	0.00	0.00
27	174 Miscellaneous Current Assets	0.00	971.14	971.14
28	Total Current and Accrued Assets	6,715,327.15	7,671,418.81	956,091.66
29	**DEFERRED DEBITS**			
30	181 Unamortized Debt Discount	0.00	0.00	0.00
31	182 Extraordinary Property Losses	0.00	0.00	0.00
32	185 Other Deferred Debits	368,668.72	368,668.72	0.00
33	Total Deferred Debits	368,668.72	368,668.72	0.00
34				
35	Total Assets and Other Debits	19,657,065.84	22,489,688.43	2,832,622.59

COMPARATIVE BALANCE SHEET Liabilities and Other Credits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	**APPROPRIATIONS**			
2	201 Appropriations for Construction	$0.00	$0.00	$0.00
3	**SURPLUS**			
4	205 Sinking Fund Reserves	$0.00	$0.00	$0.00
5	206 Loans Repayments	$1,925,000.00	$1,925,000.00	$0.00
6	207 Appropriations for Construction Repayments	$20,093.39	$20,093.39	$0.00
7	208 Unappropriated Earned Surplus (P.12)	$14,903,714.42	$17,307,278.89	$2,403,564.47
8	Total Surplus	$16,848,807.81	$19,252,372.28	$2,403,564.47
9	**LONG TERM DEBT**			
10	221 Bonds (P.6)	$0.00	$0.00	$0.00
11	231 Notes Payable (P.7)	$0.00	$0.00	$0.00
12	Total Bonds and Notes	$0.00	$0.00	$0.00
13	**CURRENT & ACCRUED LIABILITIES**			
14	232 Accounts Payable	$601,101.11	$641,992.96	$40,891.85
15	234 Payables to Municipality	$0.00	$0.00	$0.00
16	235 Customer' Deposits	$335,620.30	$358,871.67	$23,251.37
17	236 Taxes .... Collection Payable	$20,002.80	$18,903.78	($1,099.02)
18	237 Interest Accrued	$0.00	$0.00	$0.00
19	242 Miscellaneous Current and Accrued Liabilities	$85,728.31	$116.03	($85,612.28)
20	Total Current and Accrued Liabilities	$1,042,452.52	$1,019,884.44	($22,568.08)
21	**DEFERRED CREDITS**			
22	251 Unamortized Premium on Debt	$0.00	$0.00	$0.00
23	252 Customer Advances for Construction	$3,210.00	$2,100.00	($1,110.00)
24	253 Other Deferred Credits	$748,541.78	$1,201,277.98	$452,736.20
25	Total Deferred Credits	$751,751.78	$1,203,377.98	$451,626.20
26	**RESERVES**			
27	260 Reserves for Uncollectible Accounts	$0.00	$0.00	$0.00
28	261 Property Insurance Reserve	$0.00	$0.00	$0.00
29	262 Injuries and Damages Reserves	$605,394.41	$605,394.41	$0.00
30	263 Pensions and Benefits	$0.00	$0.00	$0.00
31	265 Miscellaneous Operating Reserves	$0.00	$0.00	$0.00
32	Total Reserves	$605,394.41	$605,394.41	$0.00
33	**CONTRIBUTIONS IN AID OF CONSTRUCTION**			
34	271 Contributions in Aid of Construction	$408,659.32	$408,659.32	$0.00
35	Total Liabilities and Other Credits	$19,657,065.84	$22,489,688.43	$2,832,622.59

State below if any earnings of the municipal lighting plant have been used for any purpose other than discharging indebtedness of the plant, the purpose for which used and the amount thereof.

Transferred $200,000.00 to town

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	Total: Current Year (b)	Total: Increase or (Decrease) from Preceding Year (c)
1	**OPERATING INCOME**		
2	400 Operating Revenues (P. 37 and 43)	$27,262,741.68	($1,185,423.83)
3	Operating Expenses		
4	401 Operating Expenses (P. 42 and 47)	$25,062,763.61	($1,601,328.73)
5	402 Maintenance Expenses (P. 42 and 47)	$524,498.50	($30,331.15)
6	403 Depreciation Expenses	$528,830.54	$7,365.13
7	407 Amortization of Property Losses	$0.00	$0.00
8			
9	408 Taxes (P. 49)	$24,336.43	($14,008.61)
10	Total Operating Expenses	$26,140,429.08	($1,638,303.36)
11	Operating Income	$1,122,312.60	$452,879.53
12	414 Other Utility Operating Income (P. 50)	$0.00	$0.00
13			
14	Total Operating Income	$1,122,312.60	$452,879.53
15	**OTHER INCOME**		
16	415 Income from Merchandising, Jobbing and Contract Work (P. 51)	$0.00	$0.00
17	419 Interest Income	$201,064.51	($30,574.35)
18	421 Miscellaneous Nonoperating Income	$1,433.34	($191,635.37)
19	Total Other Income	$202,497.85	($222,209.72)
20	Total Income	$1,324,810.45	$230,669.81
21	**MISCELLANEOUS INCOME DEDUCTIONS**		
22	425 Miscellaneous Amortization	$0.00	$0.00
23	426 Other Income Deductions	$140.45	($35.57)
24	Total Income Deductions	$140.45	($35.57)
25	Income Before Interest Charges	$1,324,670.00	$230,705.38
26	**INTEREST CHARGES**		
27	427 Interest on Bonds and Notes	$0.00	$0.00
28	428 Amortization of Debt Discount and Expenses	$0.00	$0.00
29	429 Amortization of Premium on Debt - Credit	$0.00	$0.00
30	431 Other Interest Expenses	$701.95	$258.33
31	432 Interest Charged to Construction - Credit	$0.00	$0.00
32	Total Interest Charges	$701.95	$258.33
33	NET INCOME	$1,323,968.05	$230,447.05

EARNED SURPLUS

Line No.	(a)	Debits (b)	Credits (c)
34	208 Unappropriated Earned Surplus (at beginning of period)		$14,903,714.42
35			
36			
37	433 Balance Transferred from Income		$1,323,968.05
38	434 Miscellaneous Credits to Surplus (P. 21)		$1,279,596.42
39	435 Miscellaneous Debits to Surplus (P. 21)		
40	436 Appropriations of Surplus (P. 21)	$200,000.00	
41	437 Surplus Applied to Depreciation		
42	208 Unappropriated Earned Surplus (at end of period)	$17,307,278.89	
43			
44	**TOTALS**	$17,507,278.89	$17,507,278.89

CASH BALANCES AT END OF YEAR (Account 131)

Line No.	Items (a)	Amount (b)
1	Operation Fund	$2,749,139.97
2	Interest Fund	$0.00
3	Bond Fund	$0.00
4	Construction Fund (128)	$0.00
5	Miscellaneous Cash (128)	$1,408,080.92
6	Insurance Escrow Reserve (128)	$726,214.32
7	Insurance Escrow - Project #6 (128)	$3 537,015.25
8		
9		
10		
11		
12		$8,420,450.46

MATERIALS AND SUPPLIES (Accounts 151-159, 163)

Summary Per Balance Sheet

Line No.	Account (a)	Amount End of Year: Electric (b)	Amount End of Year: Gas (c)
13	Fuel (Account 151) (See Schedule, Page 25)	$236,498.87	
14	Fuels Stock Expenses (Account 152)		
15	Residuals (Account 153)		
16	Plant Materials and Operating Supplies (Account 154)	$854,910.22	NOT APPLICABLE
17	Merchandise (Account 155)		
18	Other Materials and Supplies (Account 156)		
19	Nuclear Fuels Assemblies and Components - In Reactor (Account 157)		
20	Nuclear Fuels Assemblies and Components - Stock Account (Account 158)		
21	Nuclear Byproduct Materials (Account 159)		
22	Stores Expense (Account 163)		
23	Total Per Balance Sheet $	$1,091,409.09	

DEPRECIATION FUND ACCOUNT (Account 136)

Line No.	(a)	Amount (b)
24	**DEBITS**	
25	Balance of account at beginning of year	$3,004,137.73
26	Income during year from balance on deposit	$73,999.78
27	Amount transferred from income	$528,830.54
28	Reimbursement from sales of plant and damages property, etc.	$0.00
29	**TOTAL**	$3,606,968.05
30	**CREDITS**	
31	Amount expended for construction purposes(Sec.57,C164 of G.L.)	$1,740,522.19
32	Amounts expended for renewals, viz:	
33		
34		
35		
36		
37		
38		
39	Balance on hand at end of year	$1,866,445.86
40	**TOTAL**	$3,606,968.05

UTILITY PLANT - ELECTRIC

1. Report below the items of utility plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c).

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications of transfers within utility plant accounts should be shown in column (f).

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1							
2	**1. INTANGIBLE PLANT**	$3,879.76					
3							$3,879.76
4	**Total Intangible Plant**	$3,879.76					$3,879.76
5	**2. PRODUCTION PLANT**						
6	**A. Steam Production**						
7	310 Land and Land rights						
8	311 Structures and Improvements						
9	312 Boiler Plant equipment						
10	313 Engine and Engine Driven						
11	Generators						
12	314 Turbogenerator Units						
13	315 Miscellaneous Power Plant						
14	Equipment						
15	**Total Steam Production Plant**						
16	**B. Nuclear Production Plant**						
17	320 Land and Land Rights	$1,252.93	$0.00	$0.00	$0.00	$0.00	$1,252.93
18	321 Structures and Improvements	$802,247.54	$116.54	$56,033.67	$0.00	$0.00	$746,330.41
19	322 Reactor Plant Equipment	$1,194,684.26	$3,542.72	$68,441.51	$0.00	$0.00	$1,129,785.47
20	323 Turbogenerator Units	$172,829.17	($676.30)	$11,559.10	$0.00	$0.00	$160,593.77
21	324 Accessory Electric Equipment	$273,069.44	$190.61	$21,578.00	$0.00	$0.00	$251,682.05
22	325 Miscellaneous Power Plant Equipment	$87,832.77	($1,305.70)	$9,003.84	$0.00	$0.00	$77,523.23
23	**Total Nuclear Production Plant**	$2,531,916.11	$1,867.87	$166,616.12	$0.00	$0.00	$2,367,167.86

UTILITY PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	**C. Hydraulic Production Plant**						
2	330 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	331 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	332 Reservoirs, Dams and Waterways	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	333 Water Wheels, turbines and Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	334 Accessory Electric equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	335 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	336 Roads, Railroads and Bridges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	**Total Hydraulic Production Plant**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	**D. Other Production Plant**						
11	340 Land and Land Rights	$5,500.00	$0.00	$0.00	$0.00	$0.00	$5,500.00
12	341 Structures and Improvements	$7,466.59	$1,503.06	$996.89	$0.00	$0.00	$7,972.76
13	342 Fuel Holders, Producers and Accessories	$14,044.13	$0.00	$3,772.22	$0.00	$0.00	$10,271.91
14	343 Prime Movers	$90,696.42	$0.00	$9,708.37	$0.00	$0.00	$80,988.05
15	344 Generators	$4,867.07	$0.00	$486.70	$0.00	$0.00	$4,380.37
16	345 Accessory Electric Equipment	$27,316.57	$0.00	$3,016.12	$0.00	$0.00	$24,300.45
17	346 Miscellaneous Power Plant Equipment	$15,418.07	$76,117.53	$19,858.08	$0.00	$0.00	$53,697.22
18	**Total Other Production Plant**	$165,308.85	$77,620.59	$37,838.38	$0.00	$0.00	$205,091.06
19	**Total Production Plant**	$2,697,224.96	$79,488.46	$204,454.50	$0.00	$0.00	$2,572,258.92
20	**3. TRANSMISSION PLANT**						
21	350 Land and Land Rights	$53,804.14	$0.00	$0.00	$0.00	$0.00	$53,804.14
22	351 Clearing Land and Rights of Way	$6,812.85	$0.00	$0.00	$0.00	$0.00	$6,812.85
23	352 Structures and Improvements	$22,445.20	$0.00	$2,529.13	$0.00	$0.00	$19,916.07
24	353 Station Equipment	$97,504.48	$11,061.35	$10,838.88	$0.00	$0.00	$97,726.95
25	354 Towers and Fixtures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
26	355 Poles and Fixtures	$61,815.76	$0.00	$6,965.43	$0.00	$0.00	$54,850.33
27	356 Overhead Conductors and Devices	$44,396.59	$0.00	$5,002.63	$0.00	$0.00	$39,393.96
28	357 Underground Conduit	$84.95	$0.00	$9.57	$0.00	$0.00	$75.38
29	358 Underground Conduit and Devices	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	359 Roads and Trails	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	**Total Transmission Plant**	$286,863.97	$11,061.35	$25,345.64	$0.00	$0.00	$272,579.68

UTILITY PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	**4. DISTRIBUTION PLANT**						
2	360 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	361 Structures and Improvements	$5,710.36	$0.00	$643.45	$0.00	$0.00	$5,066.91
4	362 Station Equipment	$157,410.95	$1,372,032.14	$72,531.06	$5,035.00	$0.00	$1,451,877.03
5	363 Storage Batt y Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	364 Poles, Towers and Fixtures	$132,893.01	$58,913.50	$29,863.01	$27,863.74	$0.00	$134,079.76
7	365 Overhead Conductors and Devices	$564,651.62	$45,193.60	$51,113.16	$170,509.47	($330,382.64)	$57,840.25
8	366 Underground Conduit	$144,128.65	$127,165.73	$26,228.96	$9,592.75	$0.00	$235,472.67
9	367 Underground Conductors & Devices	$439,282.69	$167,192.95	$11,598.78	$35,230.14	($328,364.61)	$231,282.11
10	368 Line Transformers	$682,364.91	$130,646.25	$29,391.54	$4,029.05	$0.00	$779,590.57
11	369 Services	$157,056.28	$51,845.50	$6,957.52	$18,281.56	($93,721.61)	$89,941.09
12	370 Meters	$320,163.54	$24,331.20	$12,565.38	$7,580.74	$0.00	$324,348.62
13	371 Installations on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	372 Leased Prop. on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	373 Street Lighting and Signal Systems	$82,294.31	$26,571.80	$4,311.36	$0.00	($42,578.02)	$61,976.73
16	**Total Distribution Plant**	$2,685,956.32	$2,003,892.67	$245,204.22	$278,122.15	($795,046.88)	$3,371,475.74
17	**5. GENERAL PLANT**						
18	389 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
19	390 Structures and Improvements	$82,645.87	$37.00	$9,315.49	$20.00	$0.00	$73,347.38
20	391 Office Furniture and Equipment	$191,351.11	$26,391.46	$21,025.30	$50.00	$0.00	$196,667.27
21	392 Transportation Equipment	$176,685.25	$0.00	$19,908.97	$3,690.00	$0.00	$153,086.28
22	393 Stores Equipment	$3,429.80	$0.00	$386.47	$0.00	$0.00	$3,043.33
23	394 Tools, Shop and Garage Equipment	$7,666.53	$0.00	$493.59	$0.00	$0.00	$3,043.33
24	395 Laboratory Equipment	$6,824.54	$11,190.19	$627.00	$0.00	$0.00	$17,387.73
25	396 Power Operated Equipment	$2,031.40	$0.00	$116.55	$0.00	$0.00	$1,914.85
26	397 Communication Equipment	$17,167.17	$55.68	$1,375.11	$0.00	$0.00	$15,847.74
27	398 Miscellaneous equipment	$7,868.71	$43.86	$577.70	$0.00	$0.00	$7,334.87
28	399 Other Tangible Property	$30.35	$0.00	$0.00	$0.00	$0.00	$30.35
29	**Total General Plant**	$495,700.73	$37,718.19	$53,826.18	$3,760.00	$0.00	$475,832.74
30	**Total Electric Plant in Service**	$6,169,625.74	$2,132,160.67	$528,830.54	$281,882.15	($795,046.88)	$6,696,026.84
31	104 Utility Plant Leased to Others	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32	105 Property Held for Future Use	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
33	107 Construction Work in Progress	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
34	**Total Utility Plant Electric**	$6,169,625.74	$2,132,160.67	$528,830.54	$281,882.15	($795,046.88)	$6,696,026.84

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)
(Except Nuclear Materials)

1. Report below the information called for concerning production fuel and oil stocks.
2. Show quantities in tons of 2,000 lbs., gal., or M cf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. Show gas and electric fueled separately by specific use.

Line No.	Item (a)	Total Cost (b)	Kind of Fuel and Oil		GAS MCF	
			Quantity (c)	Cost (d)	Quantity (e)	Cost (f)
1	On Hand Beginning of Year	$271,058.27	450,693	$271,058.27	0	$0.00
2	Received During Year	$38,723.72	0	$0.00	14,122	$38,723.72
3	**TOTAL**	$309,781.99	450,693	$271,058.27	14,122	$38,723.72
4	Used During Year (Note A)	$71,600.69	56,385	$32,876.97	14,122	$38,723.72
5						
6						
7						
8						
9						
10						
11	Sold or Transferred	$1,682.43	2,786	$1,682.43	0	$0.00
12	**TOTAL DISPOSED OF**	$73,283.12	59,171	$34,559.40	14,122	$38,723.72
13	**BALANCE END OF YEAR**	$236,498.87	391,522	$236,498.87	0	$0.00

Line No.	Item (g))	Kinds of Fuel and Oil - Continued			
		Quantity (h)	Cost (i)	Quantity (j)	Cost (k)
14	On Hand Beginning of Year				
15	Received During Year				
16	**TOTAL**				
17	Used During Year (Note A)				
18					
19					
20					
21					
22					
23					
24	Sold or Transferred				
25	**TOTAL DISPOSED OF**				
26	**BALANCE END OF YEAR**				

Note A - Indicate specific purpose for which used, e.g. Boiler Oil, Make Oil, Generator Fuel, Etc.

MISCELLANEOUS NONOPERATING INCOME (ACCOUNT 421)

Line No.	Item (a)	Amount (b)
1		
2		
3		
4		
5		
6	TOTAL	

OTHER INCOME DEDUCTIONS (ACCOUNT 426)

Line No.	Item (a)	Amount (b)
7		
8		
9		
10		
11		
12		
13		
14	TOTAL	

MISCELLANEOUS CREDITS TO SURPLUS (ACCOUNT 434)

Line No.	Item (a)	Amount (b)
15	Partial Pilgrim I Settlement with Boston Edison	21,875.00
16	True Up of prior years transmission expenses	99,858.66
17	Flush Back of 1992 Project payments	1,157,862.76
18		
19		
20		
21		
22		
23	TOTAL	$1,279,596.42

MISCELLANEOUS DEBITS TO SURPLUS (ACCOUNT 435)

Line No.	Item (a)	Amount (b)
24		
25		
26		
27		
28		
29		
32	TOTAL	

APPROPRIATIONS OF SURPLUS (ACCOUNT 436)

Line No.	Item (a)	Amount (b)
33	Transfer to Town Treasury	$200,000.00
34		
35		
36		
37		
38		
39		
40	TOTAL	$200,000.00

MUNICIPAL REVENUES (ACCOUNTS 482, 444)

(K.W.H. sold under the provisions of Chapter 269, Actions of 1927)

Line No.	Acct. No.	Gas Schedule (a)	Cubic Feet (b)	Revenue Received (c)	Average Revenue per M.C.F. ($0.0000) (d)
1	482	NOT APPLICABLE			
2					
3					
4					

Line No.	Acct. No.	Electric Schedule (a)	K.W.H. (b)	Revenue Received (c)	Average Revenue perK.W.H.. (cents) (0.0000) (d)
5	444	Municipal (Other than Street Lighting)			
6					
7		All Electric	6,542,400	$600,146.91	9.1732
8		Power	4,977,059	$592,617.86	11.9070
9		Commercial	577,040	$78,487.73	13.6018
10		Yard Lighting	24,874	$3,378.43	13.5822
11		TOTALS	12,121,373	$1,274,630.93	10.5156
12					
13		Street Lighting			
14					
15		Town of Hudson	1,166,141	$130,737.00	11.2111
16		Town of Stow	27,595	$4,216.80	15.2810
17		Town of Berlin	388	$75.13	19.3634
18		TOTALS	1,194,124	$135,028.93	11.3078
19		TOTALS	13,315,497	$1,409,659.86	10.5866

PURCHASED POWER (ACCOUNT 555)

Line No.	Names of Utilities from Which Electric Energy is Purchased (a)	Where and at What Voltage Received (b)	K.W.H. (c)	Amount (d)	Cost per K.W.H. (cents) (0.0000) (e)
20	See Pages 54, 55, 56 for Details				
21					
22					
23					
24					
25					
26					
27					
28					
29		TOTALS	271,242,185	$22,189,110.10	8.1806

SALES FOR RESALE (ACCOUNT 447)

Line No.	Names of Utilities to Which Electric Energy is Purchased (a)	Where and at What Voltage Received (b)	K.W.H. (c)	Amount (d)	Revenues per K.W.H. (cents) (0.0000) (e)
30					
32					
33					
34	NONE				
35					
36					
37					
38					
39					
40		TOTALS			

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below the amount of operating revenue for the year for each prescribed account and the amount of increase or decrease over the preceding year.
2. If increases and decreases are not derived from previously reported figures, explain any inconsistencies.
3. Number of customers should be reported on the basis of number of meters, plus number of flat rate accounts, except that where separate meter readings are added for billing purposes, one customer shall be counted for each group of meters so added. The average number of customers means the average of 12 figures at the close of each month. If the customer count in the residential service classification includes customers counted more than once because of special services, such as water heating, etc., indicate in a footnote the number of such duplicate customers included in the classification
4. Unmetered sales should be included below. The details of such sales should be given in a footnote.
5. Classification of Commercial and Industrial Sales, Account 442, according to Small (or Commercial) and Large (or Industrial) may be according to the basis of classification regularly used by the respondent if such basis of classification is not greater than 1000 Kw of demand. See account 442 of the Uniform System of Accounts. Explain basis of classification.

Line No.	Account (a)	Operating Revenues		Kilowatt-hours Sold		Average Number of Customers per month	
		Amount for Year (b)	Increase of (Decrease) from Preceding Year (c)	Amount for Year (d)	Increase or (Decrease) from Preceding Year (e)	Number for Year (f)	Increase or (Decrease) from Preceding Year (g)
1	**SALES OF ELECTRICITY**						
2	440 Residential Sales	$7,391,178.23	($431,631.77)	67,593,087	2,403,747	8,666	179
3	442 Commercial and Industrial Sales:						
4	Small (or Commercial) see instr. 5	$1,704,001.18	($92,567.77)	11,747,838	699,782	1,102	(3)
5	Large (or Industrial) see instr. 5	$17,097,789.02	($778,291.18)	163,787,225	6,177,701	189	0
6	444 <Municipal Sales; (P. 22)	$1,409,659.86	($146,009.89)	13,315,497	(71,805)	88	(3)
7	445 Other Sales to Public Authorities	$0.00	$0.00	0	0	0	0
8	446 Sales to Railroads and Railways	$0.00	$0.00	0	0	0	0
9	449 Fuel Charge Adjustment	($452,199.16)	$281,139.67	0	0	0	0
10	449 Miscellaneous Electric Sales	$72,251.79	($21,165.09)	529,775	(15,530)	162	7
11	**Total Sales to Ultimate Consumers**	$27,222,680.92	($1,188,526.03)	256,973,422	9,193,895	10,207	180
12	447 Sales for Resale	$0.00	$0.00	0	0	0	0
13	**Total Sales of Electricity***	$27,222,680.92	($1,188,526.03)	256,973,422	9,193,895	10,207	180
14	**OTHER OPERATING REVENUES**						
15	450 Forfeited Discounts						
16	451 Miscellaneous Service Revenues	$0.00					
17	453 Sales of Water and Water Power	$0.00		*Includes revenues from application of fuel clauses	$		$3,329,230.10
18	454 Rent fro Electric Property	$27,484.00					
19	455 Interdepartmental Rents	$0.00					
20	456 Other Electric Revenues	$12,576.76		Total KWH to which applied			255,807,281
21							
22							
24							
25	**Total Other Operating Revenues**	$40,060.76					
26	**Total Electric Operating Revenues**	$27,262,741.68					

SALES OF ELECTRICITY TO ULTIMATE CONSUMERS

Report by account, the K.W.H. sold, the amount derived and the total number of customers under each filed schedule or contract. Contract sales and unbilled sales may be reported separately in total.

Line No.	Acct. No.	Schedule (a)	K.W.H. (b)	Revenue (c)	Average Revenue per KWH (cents) (0.0000) (d)	Number of Customers (Per Bills Rendered) July 31, (e)	Dec. 31, (f)
1	440	"A" Domestic Rate	40,185,279	$4,645,473.68	11.5601	6,572	6,620
2	442	"C" Commercial Rate	11,697,920	$1,697,237.07	14.5089	1,077	1,099
3	442	"D" Power Rate	163,787,225	$17,097,789.02	10.4390	187	189
4	440	"E" Water Heater Residential	11,026,512	$1,160,408.49	10.5238	1,139	1,148
5	440	"F" Rate All Electric	16,381,296	$1,585,296.06	9.6775	895	898
6	442	"G" Rate Commercial Heat	49,918	$6,764.11	13.5504	3	3
7	444	Street Lighting	1,194,124	$135,028.93	11.3078	3	3
8	444	Municipal Sales	12,121,373	$1,274,630.93	10.5156	90	86
9	449	Yard Lighting	529,775	$72,251.79	13.6382	159	161
10	449	Power Adjustment Charge	0	($452,199.16)			
11							
12							
13							
14							
15							
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46							
47							
48							
49		TOTAL SALES TO ULTIMATE CONSUMERS (Page 37 line 11)	256,973,422	$27,222,680.92	10.5936	10,125	10,207

ELECTRIC OPERATING AND MAINTENANCE EXPENSES

1. Enter in the pace provided the operation and maintenance expenses for the year.
2. If the increases and decreases are not derived from previously reported figures explain in footnote.

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	POWER PRODUCTION EXPENSES		
2	STEAM POWER GENERATION		
3	Operation:		
4	500 Operation supervision and engineering		
5	501 Fuel		
6	502 Steam expenses		
7	503 Steam from other sources		
8	504 Steam transferred - Cr.		
9	505 Electric expenses		
10	506 Miscellaneous steam power expenses		
11	507 Rents		
12	Total Operation	$0.00	$0.00
13	Maintenance:		
14	510 Maintenance supervision and engineering		
15	511 Maintenance of structures		
16	512 Maintenance of boiler plant		
17	513 Maintenance of electric plant		
18	514 Maintenance of miscellaneous steam plant		
19	Total Maintenance	$0.00	$0.00
20	Total power production expenses - steam power	$0.00	$0.00
21	NUCLEAR POWER GENERATION		
22	Operation:		
23	517 Operation supervision and engineering	$15,903.58	$823.03
24	518 Fuel	$41,987.43	($1,938.02)
25	519 Coolants and water	$471.97	$59.57
26	520 Steam expenses	$9,962.62	($1,677.17)
27	521 Steam from other courses	$0.00	$0.00
28	522 Steam transferred - Cr.	$0.00	$0.00
29	523 Electric expenses	$332.74	$34.04
30	524 Miscellaneous nuclear power expenses	$22,786.67	($8,177.40)
31	525 Rents	$0.00	$0.00
32	Total operation	$91,445.01	($10,875.95)
33	Maintenance		
34	528 Maintenance supervision and engineering	$4,938.02	($603.74)
35	529 Maintenance of structures	$3,293.26	($588.41)
36	530 Maintenance of reactor plant equipment	$2,327.92	($5,239.60)
37	531 Maintenance of electric plant	$3,015.04	($2,608.92)
38	532 Maintenance of miscellaneous nuclear plant	$5,924.12	($1,131.38)
39	Total maintenance	$19,498.36	($10,172.05)
40	Total power production expenses-nuclear power	$110,943.37	($21,048.00)
41	HYDRAULIC POWER GENERATION		
42	Operation		
43	535 Operation supervision and engineering		
44	536 Water for power		
45	537 Hydraulic expenses		
46	538 Electric expenses		
47	539 Miscellaneous hydraulic power generation expenses		
48	540 Rents		
49	Total operation		

ELECTRIC OPERATING AND MAINTENANCE EXPENSES - Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**HYDRAULIC POWER GENERATION - Continued**		
2	Maintenance		
3	541 Maintenance supervision and engineering		
4	542 Maintenance of structure		
5	543 Maintenance of reservoirs, dams and waterways		
6	544 Maintenance of electric plant		
7	545 Maintenance of miscellaneous hydraulic plant		
8	Total maintenance		
9	Total power production expenses - hydraulic power		
10	**OTHER POWER GENERATION**		
11	Operation		
12	546 Operation supervision and engineering	$24,956.25	$1,961.25
13	547 Fuel	$71,600.69	$19,984.28
14	548 Generation expenses	$200,333.68	$14,358.81
15	549 Miscellaneous other power generation expenses	$59,019.91	($1,953.24)
16	550 Rent	$0.00	$0.00
17	Total operation	$355,910.53	$34,351.10
18	Maintenance		
19	551 Maintenance supervision and engineering	$24,490.38	$1,688.35
20	552 Maintenance of structures	$118,662.76	$13,614.75
21	553 Maintenance of generating and electric plant	$49,104.97	($13,999.96)
22	554 Maintenance of miscellaneous other power generation plant	$4,155.48	$2,928.83
23	Total maintenance	$196,413.59	$4,231.97
24	Total power production expenses	$552,324.12	$38,583.07
25	**OTHER POWER SUPPLY EXPENSES**		
26	555 Purchased power	$22,189,110.10	($1,580,809.01)
27	556 System control and load dispatching	$25,540.84	$1,075.55
28	557 Other expenses	$28,625.67	($5,046.08)
29	Total other power supply expenses	$22,243,276.61	($1,584,779.54)
30	Total power production expenses	$22,906,544.10	($1,567,244.47)
31	**TRANSMISSION EXPENSES**		
32	Operation		
33	560 Operation supervision and engineering	$0.00	$0.00
34	561 Load dispatching	$0.00	$0.00
35	562 Station Expenses	$3,908.45	$2,312.62
36	563 Overhead line expenses	$37.32	$37.32
37	564 Underground line expenses	$0.00	$0.00
38	565 Transmission of electricity by others	$915,681.92	($61,459.14)
39	566 Miscellaneous transmission expenses	$0.00	$0.00
40	567 Rents	$50.00	$0.00
41	Total operation	$919,677.69	($59,109.20)
42	Maintenance		
43	568 Maintenance supervision and engineering	$0.00	$0.00
44	569 Maintenance of structures	$328.72	$254.88
45	570 Maintenance of station equipment	$3,166.28	$413.75
46	571 Maintenance of overhead lines	$114.86	$78.46
47	572 Maintenance of underground lines	$0.00	$0.00
48	573 Maintenance of miscellaneous transmission plant	$0.00	$0.00
49	Total maintenance	$3,609.86	$747.09
	Total transmission expenses	$923,287.55	($58,362.11)

ELECTRIC OPERATING AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**DISTRIBUTION EXPENSES**		
2	Operation:		
3	580 Operation supervision and engineering	$22,678.60	$1,067.30
4	581 Load dispatching	$0.00	$0.00
5	582 Station expenses	$287.56	$212.58
6	583 Overhead line expenses	$7,081.11	$1,319.80
7	584 Underground line expenses	$1,919.48	$1,251.80
8	585 Street lighting and signal system expenses	$8,410.21	($237.45)
9	586 Meter expenses	$45,038.35	$5,489.97
10	587 Customer installations expenses	$1,269.14	$377.02
11	588 Miscellaneous distribution expenses	$5,774.69	$2,034.66
12	589 Rents	$0.00	$0.00
13	Total operation	$92,459.14	$11,515.68
14	Maintenance:		
15	590 Maintenance supervision and engineering	$22,729.33	$1,182.56
16	591 Maintenance of structures	$0.00	$0.00
17	592 Maintenance of station equipment	$181.84	($221.40)
18	593 Maintenance of overhead lines	$189,281.54	($9,976.09)
19	594 Maintenance of underground lines	$21,243.88	($21,217.11)
20	595 Maintenance of line transformers	$8,593.71	($2,432.28)
21	596 Maintenance of street lighting and signal systems	$7,145.07	$1,808.61
22	597 Maintenance of meters	$7,014.33	$430.82
23	598 Maintenance of miscellaneous distribution plant	$0.00	$0.00
24	Total maintenance	$256,189.70	($30,424.89)
25	Total distribution expenses	$348,648.84	($18,909.21)
26	**CUSTOMERS ACCOUNTS EXPENSES**		
27	Operation:		
28	901 Supervision	$10,632.71	$2,744.05
29	902 Meter reading expenses	$47,055.81	$1,810.10
30	903 Customer records and collection expenses	$169,149.61	$5,925.15
31	904 Uncollectible accounts	$43,957.02	$20,669.97
32	905 Miscellaneous customer accounts expenses	$0.00	$0.00
33	Total customer accounts expenses	$270,795.15	$31,149.27
34	**SALES EXPENSES**		
35	Operation:		
36	911 Supervision	$0.00	$0.00
37	912 Demonstrating and selling expenses	$0.00	$0.00
38	913 Advertising expenses	$25.00	$0.00
39	916 Miscellaneous sales expenses	$11,782.88	($417.51)
40	Total sales expenses	$11,807.88	($417.51)
41	**ADMINISTRATIVE AND GENERAL EXPENSES**		
42	Operation:		
43	920 Administrative and general salaries	$319,579.16	$24,259.28
44	921 Office supplies and expenses	$9,768.45	($5,257.20)
45	922 Administrative expenses transferred - Cr.	($28.56)	($53.07)
46	923 Outside services employees	$190,962.07	$37,962.68
47	924 Property insurance	$26,748.32	($1,511.42)
48	925 Injuries and damages	$47,214.48	($92,322.42)
49	926 Employee pensions and benefits	$393,320.43	$21,707.75
50	928 Regulatory commission expenses	$3,514.72	($156.85)
51	933 Transportation expenses	$39,840.68	($11,712.34)
52	930 Miscellaneous general expenses	$46,471.85	$3,921.01
53	931 Rents	$0.00	$0.00
54	Total operation	$1,077,391.60	($23,162.58)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES - Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**ADMINISTRATIVE AND GENERAL EXPENSES - Cont.**		
2	Maintenance		
3	932 Maintenance of general plant	$48,786.99	$5,286.73
4	Total administrative and general expenses	$1,126,178.59	($17,875.85)
5	Total Electric Operation and Maintenance Expenses	$25,587,262.11	($1,631,659.88)

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
6	Power Production Expenses			
7	Electric Generation:			
8	Steam power			
9	Nuclear power	$91,445.01	$19,498.36	$110,943.37
10	Hydraulic power			
11	Other power	$355,910.53	$196,413.59	$552,324.12
12	Other power supply expenses	$22,243,276.61	$0.00	$22,243,276.61
13	Total power production expenses	$22,690,632.15	$215,911.95	$22,906,544.10
14	Transmission Expenses	$919,677.69	$3,609.86	$923,287.55
15	Distribution Expenses	$92,459.14	$256,189.70	$348,648.84
16	Customer Accounts Expenses	$270,795.15	$0.00	$270,795.15
17	Sales Expenses	$11,807.88	$0.00	$11,807.88
18	Administrative and General Expenses	$1,077,391.60	$48,786.99	$1,126,178.59
19	Total Electric Operation and			
20	Maintenance Expenses	$25,062,763.61	$524,498.50	$25,587,262.11

21 Ratio operating expenses to operating revenues (carry out decimal two places, e.g.: 0.00%) 95.88%

Complete by dividing Revenues (acct. 400) into the sum of Operation and Maintenance Expenses (Page 42, line 20(d), Depreciation (Acct. 403) and Amortization (Acct. 407)

22 Total salaries and wages of electric department for year, including amounts charged to operating expenses, construction and other accounts. $1,407,972.58

23 Total number of employees of electric department at end of year including administrative, operating, maintenance, construction and other employees (including part time employees) 34

TAXES CHARGED DURING YEAR

1. This schedule is intended to give the account distribution of total taxes charged to operations and other final accounts during the year.

2. Do not include gasoline and other sales taxes which have been charged to accounts to which the material on which the tax was levied was charged. If the actual or estimated amounts of such taxes are known, they should be shown as a footnote and designated whether estimated or actual amounts.

3. The aggregate of each kind of tax should be listed under the appropriate heading of "Federal," "State," and Local" in such manner that the total tax for each State and for all subdivisions can readily be ascertained.

4. The accounts to which the taxes charged were distributed should be shown in columns (c) to (h). Show both the utility department and number of account charged. For taxes charged to utility plant show the number of the appropriate balance sheet plant accounts or subaccount.

5. For any tax which it was necessary to apportion to more than one utility department or account, state in a footnote the basis of apportioning such tax.

6. Do not include in this schedule entries with respect to deferred income taxes, or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

Line No.	Kind of Tax (a)	Total Taxes Charged During Year (omit cents) (b)	Distribution of Taxes Charged (omit cents) (Show utility department where applicable and account charged) Electric (Acct. 408, 409) (c)	Gas (Acct. 408, 409) (d)	(e)	(f)	(g)	(h)	(j)	(k)
1	Real Estate Taxes	$21,230.29	$21,230.29							
2	Payroll Taxes	$3,106.14	$3,106.14							
3										
4										
5										
6										
7										
8										
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25										
26										
27										
28	TOTALS	$24,336.43	$24,336.43							

OTHER UTILITY OPERATION INCOME (Account 414)

Report below the particulars called for in each column.

Line No.	Property (a)	Amount of Investment (b)	Amount of Revenue (c)	Amount of Operating Expenses (d)	Gain or (Loss) from Operation (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
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12					
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14					
15					
16					
17					
18					
19					
20	NONE				
21					
22					
23					
24					
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26					
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28					
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31					
32					
33					
34					
35					
36					
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43					
44					
45					
46					
47					
48					
49					
50					
51	TOTALS				

INCOME FROM MERCHANDISING, JOBBING, AND CONTRACT WORK (Account 415)

Report by utility departments the revenues, costs, expenses and net income from merchandising, jobbing and contract work during year.

Line No.	Item (a)	Electric Department (b)	Gas Department (c)	Other Utility Department (d)	Total (e)
1	Revenues:				
2	Merchandise sales, less discounts,				
3	allowances and returns				
4	Contract work				
5	Commissions				
6	Other (list according to major classes)				
7					
8					
9					
10	Total Revenues	NONE			
11					
12					
13	Cost and Expenses:				
14	Cost of sales (list according to major				
15	classes of cost)				
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26	Sales expenses				
27	Customer accounts expenses				
28	Administrative and general expenses				
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	TOTAL COSTS AND EXPENSES				
51	Net Profit (or Loss)				

SALES FOR RESALE (Account 447)

1. Report sales during year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide subheadings and classify sales s to (1) Associated Utilities, (2) Nonassociated Utiolities, (3) Municipalitie (4) R.E.A. Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b thus: firm power, FP, or surplus power, DP; other, G, and place and "x" in column (c) if sale involves export acro line.

3. Report separately firm, dump, and other power sold t utility. Describe the nature of any sales classified as Other column (b).

4. If delivery is made at a substation indicate ownership in column (e), thus: Respondent owned or leased, RD; cust owned of leased, CS.

Line No.	Sales to (a)	(b)	(c)	Point of Delivery (d)	(e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20				NONE				
21								
22								
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42								

SALES FOR RESALE (Account 447) - Continued

5. If a fixed number of kilowatts of maximum demand is specified in the power contract as a basis of billings to the customer this number should be shown in column (f). The number of kilowatts of maximum demand to be shown in column (g) and (h) should be actual based on monthly readings and should be furnished whether or not used in the determination of demand charges, Show in column (i) type of demand reading (instantaneous, 15, 30, to 60 minutes integrated.)

6. The number of kilowatt-hours sold should be the quantities shown by the bills rendered to the purchasers.

7. Explain any amounts entered in column (n) such as fuel or other adjustments.

8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	Demand Charges (l)	Energy (m)	Other Charges (n)	Total (o)	Revenue per KWH (Cents) (0.0000) (p)	Line No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
		NONE						19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
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								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
	TOTALS							42

PURCHASED POWER (Account 555)
(except interchange power)

1. Report power purchased for resale during the year. Exclude from this schedule and report on page 56 particulars concerning interchange power transactions during the year.
2. Provide subheadings and classify purchases as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Nonassociated Utilities, (5) Municipalities, (6) R.E.A. Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b), thus: firm power, FP; dump or surplus power, DP; other, O, and place and "x" in column (c) if purchase involves import across a state line.
3. Report separately firm, dump, and other power purchased from the same company. Describe the nature of any purchases classified as Other Power, column (b).

Line No.	Purchsed from (a)	Statistical Classification (b)	Import Accros State Lines (c)	Point of Receipt (d)	Substation (e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1	Pilgrim I - Boston Edison	O		Marlboro-Hudson Line		2500	N/A	N/A
2	Vermont Yankee	O	X			578	N/A	N/A
3	Maine Yankee	O	X			1310	N/A	N/A
4	Wyman - Yarmouth - CM	O	X			2102	N/A	N/A
5	Point Lepreau	O	X			5000	N/A	N/A
6	MMWEC - Canal	O				3141	N/A	N/A
7	MMWEC - Mix No. 1	O	X			691	N/A	N/A
8	MMWEC - Project #3 - Mi	O	X			591	N/A	N/A
9	MMWEC - Project #4	O	X			2109	N/A	N/A
10	MMWEC- Project #5	O	X			235	N/A	N/A
11	MMWEC - Project #6	O	X			15972	N/A	N/A
12	Taunton - Cleary Station	O				5000	N/A	N/A
13	Pasny	O	X			2521	N/A	N/A
14	RFA - Lawrence	O				928	N/A	N/A
15	N.E. Power CO.	F				3000	N/A	N/A
16								
17								
18								
19								
20								
21								
22	Purchased Power Used at Power Plant							
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42								

PURCHASED POWER (Account 555) - Continued
(except interchange power)

4. If receipt of power is at a substation indicate owner in colum (e), thus: resondent owned or leased, RS; seller owned or leased, SS.

5. If a fixed number of kilowatts of maimum demand is specified in the power contract as a basis of billing, thi number should be shown in column (f). The number of kilowatts of maximum demand to be shown in columns (and (h) should be actual based on monthly readings and should be furnished whether or not used in the determianti of demand charges Show in column (i) type of demand reading (instantaneous, 15, 30, or 60 minutes integrated).

6. The number of kilowatt hours purchased should be t quantities shown by the power bills.

7. Explain any amount entered in column (n) such as fu or other adjustments.

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	Charges (l)	Energy Charges (m)	Other Charges (n)	Total (o)	Cost per KWH (Cents) (0.0000) (p)	Line No.
NA	115 kv	16,196,746	$1,253,409	$82,050	$37,596	$1,373,055	8.4774	1
NA	115 kv	3,749,827	$166,038	$21,714	$12,569	$200,321	5.3421	2
NA	115 kv	8,514,537	$235,238	$38,416	$13,493	$287,147	3.3724	3
NA	115 kv	1,286,957	$105,887	$37,939	$0	$143,826	11.1757	4
NA	115 kv	38,194,800	$1,413,639	$60,741	$0	$1,474,380	3.8602	5
NA	115 kv	9,881,852	$142,138	$212,188	$0	$354,326	3.5856	6
NA	115 kv	4,052,543	$549,283	$13,954	$0	$563,237	13.8984	7
NA	115 kv	3,333,672	$346,975	$10,328	$0	$357,303	10.7180	8
NA	115 kv	16,581,203	$1,255,380	$97,713	$0	$1,353,093	8.1604	9
NA	115 kv	1,846,773	$158,369	$10,883	$0	$169,252	9.1647	10
NA	115 kv	125,560,139	$13,588,497	$739,929	$0	$14,328,426	11.4116	11
NA	115 kv	2,619,344	$305,091	$88,668	$0	$393,759	15.0327	12
NA	115 kv	19,114,961	$109,817	$0	$0	$109,817	0.5745	13
NA	115 kv	2,837,376	$0	$232,665	$0	$232,665	8.2000	14
NA	115 kv	45,000	$0	$1,215	$0	$1,215	2.7000	15
								16
								17
								18
CHARGED TO ACCOUNT 549		(1,595,868)			($34,046)	($34,046)		19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
	TOTALS	252,219,862	$19,629,761	$1,648,403	$29,612	$21,307,776	8.4481	42

INTERCHANGE POWER (Included in Account 555)

1. Report below the kilowatt-hours received and delivered during the year and the net charge or credit under interchange power agreements.

2. Provide subheadings and classify interchanges as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) R.E.A. Cooperatives, and (7) Other Public Authorities. For each interchange across a state line place an "x" in column (b).

3. Particulars of settlements for interchange power shall be furnished in Part B, Details of Settlement for Interchange Power. If settlement for any transaction also includes credit or debit amounts other than for increment generation expenses, show such other component amounts separately, in addition to debit or credit for increment generation expenses, and give a brief explanation of the factors and principles under which such other component amounts were determined. If such settlement represents the net of debits and credits under an interconnection, power pooling, coordination, or other such arrangement, submit a copy of the annual summary of transactions and billings among the parties to the agreement. If the amount of settlement reported in this schedule for any transaction does not represent all of the charges and credits covered by the agreement, furnish in a footnote a description of the other debits and credits and state the amount and accounts in which such other amounts are included for the year.

A. Summary of Interchange According to Companies and Points of Interchange

Line No.	Name of Company (a)	Interchange Across State Lines (b)	Point of Interchange (c)	Voltage at Which Interchanged (d)	Kilowatt-Hours Received (e)	Kilowatt-Hours Delivered (f)	Kilowatt-Hours Net Difference (g)	Amount of Settlement (h)
1	NEPEX		Hudson-Marlboro Town Lin	115 KV	38,120,155	18,965,620	19,154,535	$887,037.49
2	USED AS STATION POWER AND CHARGED TO (549)				(132,212)		(132,212)	($5,703.52)
3								
4								
5								
6								
7								
8								
9								
10								
11								
12				TOTALS	37,987,943	18,965,620	19,022,323	$881,333.97

B. Details of Settlement for Interchange Power

Line No.	Name of Company (i)	Explanation (j)		Amount (k)
13	NEPEX	Energy Received by H.L.& P.	-Economy	$1,087,012.87
14			-Scheduled Outage	$48,353.42
15			-Unscheduled Outage	$63,132.32
16			-Deficiency	$0.00
17		Energy Dollars from NEPOOL		($210,189.26)
18		Quebec Net Savings Fund		($63,352.87)
19		NEPOOL Savings		($125,444.67)
20		NEPOOL Expenses		$65,653.21
21		Other		$21,872.47
			TOTAL	$887,037.49

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)			Kilowatt-hours (b)
1	**SOURCES OF ENERGY**			
2	Generation (excluding station use):			
3	Steam			0
4	Nuclear			6,999,514
5	Hydro			0
6	Other (DIESEL)			1,792,704
7	Total Generation			8,792,218
8	Purchases			252,219,862
9		In (gross)	37,987,943	*****
10	Interchanges	Out (gross)	18,965,620	*****
11		Net (kwh)		19,022,323
12		Received		
13	Transmission for/by others (wheeling)	Delivered		
14		Net (kwh)		
15	TOTAL			280,034,403
16	**DISPOSITION OF ENERGY**			
17	Sales to ultimate consumers (including interdepartmental sales)			256,973,422
18	Sales for resale			0
19	Energy furnished without charge			0
20	Energy used by the company (excluding station use):			
21	Electric department only			329,019
22	Energy losses:			
23	Transmission and conversion losses		11,044,879	
24	Distribution losses		8,004,959	
25	Unaccounted for losses		3,682,124	
26	Total energy losses			22,731,962
27	Energy losses as percent of total on line 15	8.1176%		
28			TOTAL	280,034,403

MONTHLY PEAKS AND OUTPUT

1. Report hereunder the information called for pertaining to simultaneously peaks established monthly (in kilowatts) and monthly output (in kilowatt-hours) for the combined sources of electric energy of respondent.
2. Monthly peak col. (b) should be respondent's maximum kw load as measured by the sum of its coincidental net generation and purchase plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system. Monthly peak including such emergency deliveries should be shown in a footnote with a brief explanation as to the nature of the emergency.
3. State type of monthly peak reading (Instantaneous, 15, 30, or 60 minutes integrated.)
4. Monthly output should be the sum of respondent's net generation and purchases plus or minus net interchange and plus or minus net transmission of wheeling. Total for the year should agree with line 15 above.
5. If the respondent has two or more power systems not physically connected, the information called for below should be furnished for each system.

Line No.	Month (a)	Kilowatts (b)	Day of Week (c)	Day of Mont (d)	Hour (e)	Type of Reading (f)	Monthly Output (kwh) (See Instr. 4) (g)
29	January	41,700	TUESDAY	19	9:00	60 Min.	24,441,255
30	February	41,300	TUESDAY	2	9:00	60 Min.	22,904,722
31	March	40,000	FRIDAY	19	8:00	60 Min.	23,955,702
32	April	37,700	FRIDAY	2	10:00	60 Min.	21,323,590
33	May	36,600	TUESDAY	11	15:00	60 Min.	20,831,556
34	June	41,300	MONDAY	28	14:00	60 Min.	21,950,380
35	July	44,700	WEDNESDAY	7	15:00	60 Min.	24,119,558
36	August	45,600	THURSDAY	26	16:00	60 Min.	24,725,556
37	September	44,800	FRIDAY	3	14:00	60 Min.	21,026,127
38	October	37,800	WEDNESDAY	27	12:00	60 Min.	23,220,072
39	November	40,000	TUESDAY	30	19:00	60 Min.	22,389,894
40	December	42,800	MONDAY	27	18:00	60 Min.	29,145,991
41						TOTAL	280,034,403

GENERATING STATION STATISTIC (Large Stations)
***Limited to 15,200 by Diesel**
(Except Nuclear, See Instruction 10)

1. Large stations for this purpose of this schedule are steam and stations of 2,699 Kw* or more of installed capacity and other statio 500 Kw* of more of installed capacity (name plate ratings). (*10,0 and 2,600 Kw, respectively, if annual electric operating revenue of spondent are $25,000,000 or more.)
2. If any plant is leased, operated under a license from the Feder Power Commission, or operated as a joint facility, indicate such fa
4. If peak demand for 60 minutes is not available, give that which is available, specifying period.
5. If a group of employees attends more than one generating station, report on line 11 the approximate average number of employees assignable to each station.
6. If gas is used and purchased on a therm basis, the B.t.u. content of the gas should be given and the quantity of fuel converted to cy. ft.

Line No.	Item (a)	Plant Cherry St. Sta.	Plant HLP Peaking	Plant (d)
1	Kind of plant (steam, hydro, int. comb., gas turbine)	Int. Comb.	Int. Comb.	
2	Type of plant construction (conventional, out-door, boiler, full outdoor, etc.)	Conventional	Conventional	
3	Year originally constructed	1897	1962	
4	Year last unit was installed	1972	1962	
5	Total installed capacity (maximum generator name plate ratings in kw)	16,150*	4,400	
6	Net peak demand on plant-kilowatts (60 min.)	15.2	2.8	
7	Plant hours connected to load	221	137	
8	Net continuous plant capability, kilowatts:			
9	(a) When not limited by condensed water	15,200	4,400	
10	(b) When limited by condensed water	15,200	4,400	
11	Average number of employees	12		
12	Net generation, exclusive of station use	1,455,744	336,960	
13	Cost of plan (omit cents)			
14	Land and land rights	$5,500		
15	Structures and improvements	$332,768		
16	Reservoirs, dams and waterways			
17	Equipment costs	$3,117,645	712,054	
18	Roads, railroads and bridges			
19	Total Cost	$3,455,913	712,054	
20	Cost per kw of installed capacity	227	162	
21	Production expenses:			
22	Operation supervision and engineering	$24,956.25		
23	Station labor	$196,638.68		
24	Fuel	$71,600.69		
25	Supplies and expenses, including water	$62,714.91		
26	Maintenance	$196,413.59		
27	Rents	$0.00		
28	Steam from other sources	$0.00		
29	Steam transferred - Credit	$0.00		
30	Total production expenses	$552,324.12		
31	Expenses per net KWH (5 places)	$0.30810		
32	Fuel: kind	#2 Diesel	Natural Gas	
33	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-M cu. ft.) (Nuclear, indicate)	42 Gal	M Cu Ft	
34	Quantity (units) of fuel consumed	1,342	14,122	
35	Average heat content of fuel (B.t.u. per lb. of coal, per gal. of oil, or per cu. ft. of gas)	140,000 Btu	910 BTU	
36	Average cost of fuel per unit, del. f.o.b plant		$2.74208 MCF	
37	Average cost of fuel per unit consumed	24.4985 BBL	$2.74208 MCF	
38	Average cost of fuel consumed per million B.t.u	$4.16485	$3.01320	
39	Average cost of fuel consumed per kwh net gen.	$0.03994		
40	Average B.t.u. per kwh net generation	11,571		
41				
42				

GENERATING STATION STATISTIC (Large Stations)

The Hudson Light & Power Department is a .07737% owner of Seabrook Unit #1 located at Seabrook, N.H. The 1993 generation statistics are as follows:

Line No.	Item (a)	Plant (b)
1	Kind of Plant	Nuclear
2	Type of Plant Construction	Fully Contained
3	Year Originally Constructed	1,990
4	Year Last Unit Was Installed	1,990
5	Total Installed Capacity	1197 MW
6	Net Peak Demand On Plant	1157 MWH
7	Plant Hours Connected To Load	8,096
8	Net Continuous Plant Capability	
9	(a) When not limited by condenser water	1,150
10	(b) When limited by condenser water	1,150
11	Average number of employees	960
12	Net generation, exclusive of station use	9,046,805,000 KWH
13	Fuel: Kind	Nuclear
14	Unit	Grams
15	Quantity of Fuel Burned	1,478,164
16	Average Heat Content of Fuel Burned	62.1 MMBTU/Gr
17	Average BTU Per KWH Net Generation	10,151.6 BTU
18		
19		
20		
21		
22		
23		
24		
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41		
42		

GENERATING STATION STATISTICS (Large Stations) - Continued
(Except Nuclear, See Instruction 10)

547 as shown on line 24.

8. The items under cost of plant and production expenses repres accounts or combinations of accounts prescribed by the Uniform S of Accounts. Production expenses, however, do not include Purch Power, System Control and Load Dispatching, and Other Expense classified as "Other Power Supply Expenses."

9. If any plant is equipped with combinations of steam, hydro, i combustion engine or gas turbine equipment, each should be repor separate plant. However, if a gas turbine unit functions in a combi operation with a conventional steam unit, the gas turbine should be inc

10. If the respondent operates a nuclear power generating station submit: (a) a brief explanatory statement concerning accounting for th cost of power generated including any attribution of excess costs to res and development expenses; (b) a brief explanation of the fuel accounti specifying the accounting methods and types of cost units used with respect to the various components of the fuel cost, and (c) such additio information as may be informative concerning the type of plant, kind o fuel used, and other physical and operating characteristics of the plant

Plant (e)	Plant (f)	Plant (g)	Plant (h)	Plant (i)	Plant (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						36
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						38
						39
						40
						41
						42

STEAM GENERATING STATIONS

1. Report the information called for concerning g ating stations and equipment at end of year.
2. Exclude from this schedule, plant, the book co which is included in Account 121, Nonutility Proper
3. Designate any generating station or portion the for which the respondent is not the sole owner. If s property is leased from another company, give nam lessor, date and terms of lease, and annual rent. For any generating station, other than a leased station or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation o furnish a succinct statement explaining the arrangement a give particulars as to such matters as percent ownership by respondent, name and co-owner, basis of sharing outp

Line No.	Name of Station (a)	Location of Station (b)	BOILERS Number and Year Installed (c)	Kind of Fuel and Method of Firing (d)	Rated Pressure in lbs. (e)	Rated Steam Temperature* (f)	Rated Max. Continuous M lbs Steam per hour (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20		NOT APPLI	CABLE				
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							

*Indicate reheat boilers thusly, 1050/1000

STEAM GENERATING STATIONS - Continued

expenses or revenues, and how expenses and/or revenues accounts for an accounts affected. Specify if lesser, co-owner, or other party is an associate company.

4. Designate any generating station or portion thereof leased to another company and give name of lessee, date terms of lease and annual rent and how determined. Spe whether lessee is an associated company.

5. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant c; equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Turbine-Generators*

Year Installed (h)	Type~ (i)	Steam Pressure at Throttle p.s.i.? (j)	R.P.M. (k)	Name Plate Rating in Kilowatts: At Minimum Hydrogen Pressure (l)	Name Plate Rating in Kilowatts: at Maximum Hydrogen Pressure (m)	Hydrogen Pressure~~ Min. (n)	Hydrogen Pressure~~ Max. (o)	Power Factor (p)	Voltage K.v.~~~ (p)	Station Capacity Maximum Name Plate Rating~~~~ (r)	Line No.
											1
											2
											3
											4
											5
											6
											7
											8
											9
											10
											11
											12
											13
											14
											15
											16
											17
				NOT APPLICABLE							18
											18
											20
											21
											22
											23
											24
											26
											27
											28
											29
											30
											31
											32
											33
											34
											35
											36
			TOTALS								37

Note References:

*Report cross-compound turbine-generator units on two lines - H.P. section and L.P. section

~Indicate tandem-compount (T.C.); cross compound (C.C.); all single casing (S.C.); topping unit (T), and noncondensing (N.C.). Show back pressures.

~~Designate air cooled generators

~~~If other than 3 phase, 60 cycle, indicate other characteristic.

~~~~Should agree with column (m).

HYDROELECTRIC GENERATING STATIONS

1. Report the information called for concerning generating stations and equipment at end of year.
2. Exclude from this schedule, plant, the book cost of which is included in Account 121, Nonutility Property.
3. Designate any generating station or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and annual rent. For any generating station, other than a leased station or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and give particulars as to such matters as percent ownership by respondent, name and co-owner, basis of sharing output,

Line No.	Name of Station (a)	Location (b)	Name of Stream (c)	Water Wheels: Attended or Unattended (d)	Water Wheels: Type of Unit (e)	Water Wheels: Year Installed (f)	Water Wheels: Gross Static Head With Pond Full (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20			NOT APPLICABLE				
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
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37							

*Horizontal or vertical. Also indicate type of runner - Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), Impulse (I).

HYDROELECTRIC GENERATING STATIONS (Continued)

percent of ownership by respondent, name of co-owne basis of sharing output, expenses, or revenues, and ho expenses and/or revenues are accounted for and accou affected. Specify if lessor, co-owner, or other part is a associated company.

4. Designate any generating station or portion there leased to another company and give name of lessee, da and term of lease and annual rent and how determined. Specify whether lessee is an associated company.

5. Designate any plant or equipment owned, not operated and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Water-Wheels - Continued			Generators							
Design Head (h)	R.P.M. (i)	Maximum hp. Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Fre-quency or d.c. (n)	Name Plate Rating of Unit in Kilowatts (o)	Number of Units in Station (p)	Total Installed Generating Capacity in Kil-owatts (name plate ratings.) (q)	Line No.
										1
										2
										3
										4
										5
										6
										7
										8
										9
										10
										11
										12
										13
										14
										15
										16
										17
										18
										19
			NOT APPLICABLE							20
										21
										22
										23
										24
										25
										26
										27
										28
										29
										30
										31
										32
										33
										34
										35
										36
										37
			TOTALS							39

COMBUSTION ENGINE AND OTHER GENERATING STATIONS
(except nuclear stations)

1. Report the information called for concerning generating stations and equipment at end of year. Show associated prime movers and generators on the same line.
2. Exclude from this schedule, plant, the book cost of which is included in Account 121, Nonutility Property.
3. Designate any generating station or portion thereof for which the respondent is not the sole owner property is leased from another company, give name of lessor, date and terms of lease, and annual rent. For any generating station, other than a leased station, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars as to such matters as percentage owner

Line No.	Name of Station (a)	Location of Station (b)	Prime Movers: Diesel or Other Type Engine (c)	Name of Maker (d)	Year Installed (e)	2 or 4 Cycle (f)	Belted or Direct Connected (g)
1	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co.	1951	2	Direct
2	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co	1955	2	Direct
3	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co.	1960	2	Direct
4	Cherry St	Cherry Street, Hudson	Diesel	Cooper-Bessemer	1972	4	Direct
5							
6							
7							
8							
9							
10	Hudson Light	Cherry Street, Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
11	Peaking Plt.	Cherry Street, Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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38							
39							

COMBUSTION ENGINE AND OTHER GENERATING STATIONS - Continued
(except nuclear stations)

ship by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

4. Designate any generating station or portion thereof leased to another company and give name of lessee, date and terms of lease and annual rent and how determined. Specify whether lessee is an associated member.

5. Designate any plant or equipment owned, not operated and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Prime Movers _ Continued		Generators						Total Installed	
Rated hp. of Unit (h)	Total Rated hp. of Station Prime Movers (i)	Year Installed (j)	Voltage (k)	Phase (l)	Frequency or d.c. (m)	Name Plate Rating of Unit In Kilowatts (n)	Numbers of Units in Station (o)	Generating Capacity In Kilowatts (name plate rating) (p)	Line No.
4,250	4,250	1951	4,160	3 ph	60 cyl.	3,300	1	3,000	1
5,100	9,350	1955	4,160	3 ph	60 cyl.	4,000	1	3,600	2
4,250	13,600	1943	4,160	3 ph	60 cyl.	3,250	1	3,000	3
7,760	21,360	1972	4,160	3 ph	60 cyl.	5,600	1	5,600	4
									5
									6
									7
									8
									9
3,168	3,168	1962	4,160	3 ph	60 cyl.	2,200	1	2,200	10
3,168	6,336	1962	4,160	3 ph	60 cyl.	2,200	1	2,200	11
									12
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									38
									38
					TOTALS	20,550	6	19,600	39

GENERATING STATION STATISTICS (Small Stations)

1. Small generating stations, for the purpose of this schedule are steam and hydro stations of less than 2,500 KW * and other stations of less than 400 KW * installed capacity (name plate ratings). (*10,000 KW and 2,500 KW, respectively, if annual electric operating revenues of respondent are $25,000,000 or more.)

2. Designate any plant leased from others, operated under a license from the Federal Power Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote.

3. List plants appropriately under subheadings for steam, hydro, nuclear internal combustion engine and gas turbine stations. For nuclear, see instruction 10 page 59.

4. Specify, if total plant capacity is reported in kva instead of kilowatts.

5. If peak demand for 60 minutes is not available, give that which is available, specifying period.

6. If any plant is equipped with combinations of steam, hydro, internal combustion engine or gas turbine equipment, each should be reported as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, report as one plant.

Line No.	Name of Plant (a)	Year Const. (b)	Installed Capacity Name Plate Rating-KW (c)	Peak Demand KW (60 Min.) (d)	Generation Excluding Station Use (e)	Cost of Plant (Omit cents) (f)	Plant Cost\ Per KW Ins. Capacity (g)	Production Expenses Exclusive of Depreciation and Taxes (Omit Cents) Labor\ (h)	Fuel (i)	Other (j)	Kind of Fuel (k)	Fuel Cost Per KWH Net Generation (Cents) (0.0000) (l)
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14					NOT APPLICABLE							
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28		TOTALS										

TRANSMISSION LINE STATISTICS

Report information concerning transmission lines as indicated below.

Line No.	Designation From (a)	Designation To (b)	Operating Voltage (c)	Type of Supporting Structure (d)	Length (Pole miles) On Structures of Line Designated (e)	Length (Pole miles) On Structures of Another Line (f)	Number of Circuits (g)	Size of Conductor and Material (h)
1	Marlboro-Hudson	Forest Avenue						
2	Town lines	Substation,	115 KV	Steel poles	3.2			336.4 MCM
3	at River Street	Hudson					2	ACSR
4								"Linnet"
47				TOTALS	3.2	None	2	

*Where other than 60 cycle, 3 phase, so indicate.

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve but one industrial or street railway customer should not be listed hereunder.
3. Substations with capacity of less than 5,000 kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation designating whether transmission or distribution and whether attended or unattended.
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc., and auxiliary equipment from increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give nature of lessor, date and period of lease and annual rent. For any substation or equipment operated other than by reasons of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses of other accounting between the parties, and state amounts and accounts affected in respondent's book of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	Voltage: Primary (c)	Voltage: Secondary (d)	Voltage: Tertiary (e)	Capacity of Substation In kva (In Service) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Cherry Street, Hudson, MA	Unattended	80001	24001	Not Brought	19,200	2	None	None	None	None
2		Distribution	13800	4160	Out						
3											
4											
5	Forest Avenue, Hudson, MA	Unattended									
6		13.8 Distribution									
7		& Diesel Tie	115 KV	80001	NA	80,000	2	None	None	None	None
8		Tie with NEPCO		13800							
9											
10											
11											
12											
13											
14											
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30											
31											
32					TOTALS	99,200	4	None	None	None	None

OVERHEAD DISTRIBUTION LINES OPERATED

Line No.		Length (Pole Miles)		
		Wood Poles	Steel Towers	Total
1	Miles - Beginning of Year	181.5		181.5
2	Added During Year	0.3		0.3
3	Retired During Year	None		None
4	Miles - End of Year	181.8		181.8
5				
6				
7				
8	Distribution System Characteristics - A.C. or D.C., phase. cycles and operating voltages for Light and Power.			
9				
10	Primary distribution at 2400/4160Y, 4800/8300Y, 8000/13800Y volts, 60 cycle,			
11	3 phase secondary power at 600 volts, 60 cycle, 3 phase 3 wire; 480 volts 3			
12	phase, 3 wire; 277/480 volts, 3 phase 4 wire; 220 volts, 3 phase 3 or 4 wire;			
13	120/208 volts, 3 phase, 4 wire lighing, heating and air conditioning			
14	120/240 colts, 120/208 volts, 60 cycle single or three phase.			
15				

ELECTRIC DISTRIBUTION SERVICES, METERS AND LINE TRANSFORMERS

Line No.	Item	Electric Services	Number of Watt-Hour Meters	Line Transformers	
				Number	Total Capacity (kva)
16	Number at beginning of year	7,758	10,637	3,163	91,531.5
17	Added during year:				
18	Purchased		201	131	5,145.0
19	Installed	84			
20	Associated with utility plant acquired		None	None	None
21	Total additions	84	201	131	5,145.0
22	Reductions during year:				
23	Retirements	38	150	12	170.0
24	Associated with utility plant sold	None	None	None	None
25	Total reductions	38	150	12	170.0
26	Number at End of Year	7,804	10,688	3,282	96,506.5
27	In stock		617	425	17,363.0
28	Locked meters on customers' premises		None	None	None
29	Inactive transformers on system		None	None	None
30	In customers' use		10,046	2,849	79,009.5
31	In company's use		25	8	134.0
32	Number at End of Year		10,688	3,282	96,506.5

CONDUIT, UNDERGROUND CABLE AND SUBMARINE CABLE - (Distribution System)

Report below the information called for concerning conduit, underground cable, and submarine cable at end of year.

Line No.	Designation of Underground Distribution System (a)	Miles of Conduit Bank (All Sizes and Types) (b)	Underground Cable		Submarine Cable	
			Miles* (c)	Operating Voltage (d)	Feet* (e)	Operating Voltage (f)
1	Route 495 Underpass	0.10	0.10	13,800		
2	Harvard Acres Estates, Stow	6.50	6.50	13,800		
3	Meadowbrook Mobile Home Park, Hudson	1.80	1.90	13,800		
4	Colburn and Margaret Circle, Hudson	0.00	0.20	4,800		
5	Main, Felton and Central Street, Hudson	0.70	0.70	13,800		
6	Seven Star Lane, Stow	0.00	0.09	4,800		
7	Forest Avenue, Hudson	1.50	1.50	13,800		
8	Juniper Estates, Stow	0.50	0.50	13,800		
9	Carriage Lane, Stow	0.19	0.33	4,800		
10	Brigham Circle, Hudson	0.90	0.90	13,800		
11	Rustic Lane, Hudson	0.00	0.20	4,800		
12	Wildwood Subdivision, Stow	0.00	0.60	13,800		
13	Birch Hill Estates, Stow	3.60	3.60	13,800		
14	Appleton Drive, Hudson	0.10	0.10	13,800		
15	Cedar Street, Hudson	0.03	0.03	4,800		
16	Country Estates, Hudson	0.00	0.34	4,800		
17	Deacon Benham Drive, Stow	0.00	0.07	8,320		
18	Forest Road, Stow	0.00	0.22	8,320		
19	Francis Circle, Stow	0.00	0.10	4,800		
20	Karen Circle, Hudson	0.00	0.07	8,320		
21	Main Street, Hudson (Whispering Pines)	0.11	0.11	13,800		
22	Glen Road, Hudson	0.24	0.24	13,800		
23	Brigham Street, Hudson (Valley Park)	0.14	0.14	13,800		
24	Brigham Street, Hudson (Assabet Village)	0.23	0.23	13,800		
25	Chapin Road, Hudson	0.07	0.07	13,800		
26	Cahill Raylor Road, Stow	0.25	0.25	13,800		
27	Great Road, Stow	0.07	0.07	13,800		
28	Kane Industrial Drive, Hudson (Digital)	0.05	0.05	13,800		
29	Peter's Grove, Hudson	0.05	0.05	13,800		
30	Johnston Way, Stow	0.20	0.20	13,800		
31	Hudson Town Hall, Hudson	0.08	0.08	13,800		
32	Sudbury Road, Stow (Off Pole 121)	0.23	0.23	13,800		
33	Parmenter Road, Hudson (Off Pole 16-1)	0.10	0.10	13,800		
34	TOTALS	17.74	19.87		None	None

*Indicate number of conductors per cable.

Annual report of TOWN OF HUDSON LIGHT AND POWER DEPARTMENT

Year ended December 31, 1993

CONDUIT, UNDERGROUND CABLE AND SUBMARINE CABLE - (Distribution System)

Report below the information called for concerning conduit, underground cable, and submarine cable at end of year.

Line No.	Designation of Underground Distribution System (a)	Miles of Conduit Bank (All Sizes and Types) (b)	Underground Cable		Submarine Cable	
			Miles* (c)	Operating Voltage (d)	Feet* (e)	Operating Voltage (f)
1	Technology Drive, Hudson	0.28	0.28	13,800		
2	Reed Road, Hudson	0.11	0.11	13,800		
3	Central St. Hudson	0.06	0.06	13,800		
4	Washington St., Hudson	0.10	0.10	13,800		
5	Barton Road, Stow	0.26	0.26	13,800		
6	Causeway St. Hudson	0.12	0.12	13,800		
7	Off Harvard Rd., Stow	0.07	0.07	13,800		
8	Off River Rd. Hudson	0.05	0.05	13,800		
9	Hazelwood Drive, Hudson	0.24	0.24	4,160		
10	Maura Drive, Stow	0.19	0.19	13,800		
11	Shay Rd. Hudson	0.07	0.07	13,800		
12	Ashford Meadows, Hudson	0.99	0.99	13,800		
13	Indian Ridge Estates, Hudson	1.31	1.31	13,800		
14	Boxmill Rd., Stow	0.13	0.13	13,800		
15	Brigham Estates, Hudson	0.61	0.61	13,800		
16	October Lane, Stow	0.24	0.24	13,800		
17	Santos Drive, Hudson	0.12	0.12	8,320		
18	Kerrington Way, Stow	0.07	0.07	13,800		
19	Bennett St., Hudson	0.39	0.39	13,800		
20	Solo Rd., Hudson	0.28	0.28	13,800		
21	Cabot Rd., Hudson	0.22	0.22	13,800		
22	Beechnut Rd., Hudson	0.14	0.14	13,800		
23	Bonazzoli Ave., Hudson	0.16	0.16	13,800		
24	Red Acre Estates, Stow	1.08	1.08	13,800		
25	Merritt Drive, Hudson	0.09	0.09	13,800		
26	Orchard Drive, Hudson	0.50	0.50	13,800		
27	Annie Terrace Drive, Hudson	0.20	0.20	13,800		
28	Heath Hen Trail, Stow	0.26	0.26	13,800		
29	Appleblossom Lane, Stow	0.34	0.34	13,800		
30	Walmart, Hudson	0.97	0.97	13,800		
31	Blueberry Lane, Hudson	0.58	0.58	13,800		
32	Stow Farms, Stow	0.86	0.86	13,800		
33	Forance Woods, Hudson	0.21	0.21	13,800		
34	TOTALS	11.30	11.30		None	None

*Indicate number of conductors per cable.

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town (a)	Total (b)	Type: Incasdescent Municipal (c)	Incasdescent Other (d)	Mercury Vapor Municipal (e)	Mercury Vapor Other (f)	Fluorescent Municipal (g)	Fluorescent Other (h)	H. P. Sodium Municipal (i)	H. P. Sodium Other (j)
1	Hudson	1,912	389	15	909	233			242	124
2	Stow	77	4	2	7	35			19	10
3	Berlin	1	1							
4	Marlboro	4				1				3
5	Bolton	1				1				
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49										
50										
51										
52	TOTAL	1995	394	17	916	270			261	137

RATE SCHEDULE INFORMATION

1. Attach copies of all Field Rates for General Consumers.

2. Show below the changes in rate schedule during year and the estimated increase or decrease in annual revenue predicted on the previous year's operations.

Date Effective	M.D.P.U. Number	Rate Schedule	Estimated Effect on Annual Revenues	
			Increases	Decreases
09/01/92	140	Domestic Rate "A"		
09/01/92	141	Commercial All Electric Rate "G"		
09/01/92	142	Commercial and Industrial Rate "D"		
09/01/92	143	Residential Water Heater Rate "E"		
09/01/92	144	Residential All Electric Rate "F"		
09/01/92	145	General or Commercial Rate "C"		
09/01/92	146	Street Lighting Schedule		
09/01/92	147	Power Adjustment Charge	N/C	

THIS RETURN IS SIGNED UNDER THE PENALTIES OF PERJURY

_______________________________ *Mayor*

Horst Huehmer
HORST HUEHMER _______________________________ *Manager of Electric Light*

Roland L. Plante
ROLAND L. PLANTE _______________________________

Peter R. Keane
PETER R. KEANE _______________________________

Weedon G. Parris Jr.
WEEDON G. PARRIS JR. _______________________________

Selectmen or Members of the Municipal Light Board

SIGNATURES OF ABOVE PARTIES AFFIXED OUTSIDE THE COMMONWEALTH OF MASSACHUSETTS MUST BE PROPERLY SWORN TO

_______________________________ ss _______________ 19

Then personally appeared

____

____

____

____

and severally made oath to the truth of the foregoing statement by them subscribed according to their best knowledge and belief

Notary Public or Justice of the Peace.

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AZ-1-10

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)

For the fiscal year ended December 31, 1993

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

Commission File Number 33-10978

GREAT BAY POWER CORPORATION

(f.k.a. EUA Power Corporation)

(Exact name of registrant as specified in its charter)

Debtor and Debtor-in-Possession under Chapter 11 of the Bankruptcy Code

New Hampshire	02-0396811
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
Forty Stark Street, P.O. Box 326 Manchester, N.H.	03105
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (617) 357-9590

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

Title of each Class	*Name of each Exchange on which registered*
None	

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

None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this form 10-K. [✓]

State the aggregate market value of the voting stock held by non-affiliates of the registrant. As of March 1, 1994:

None

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

Common Shares Outstanding at March 1, 1994

None

Documents Incorporated by Reference

None

GREAT BAY POWER CORPORATION, Debtor and Debtor-in-Possession

1993 Annual Report on Form 10-K
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PART I

PART II

PART III

PART IV

GLOSSARY OF DEFINED TERMS

The following is a glossary of frequently used abbreviations or acronyms found throughout this report:

The EUA System Companies

EUA	Eastern Utilities Associates
EUA Power	EUA Power Corporation, now known as Great Bay Power Corporation
EUA Service	EUA Service Corporation
EUA System	EUA and Subsidiary Companies
Montaup	Montaup Electric Company

Companies

Company	Great Bay Power Corporation
Great Bay	Great Bay Power Corporation
Registrant	Great Bay Power Corporation
CL&P	Connecticut Light & Power Company
UI	United Illuminating
UNITIL	UNITIL Corporation

Regulators/Regulations

1935 Act	Public Utility Holding Company Act of 1935
Bankruptcy Court	United States Bankruptcy Court for the District of New Hampshire
DOE	Department of Energy
Energy Act	Energy Policy Act of 1992
EPA	Federal Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NHIDA	Industrial Development Authority of the State of New Hampshire
NHPUC	New Hampshire Public Utility Commission
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act
Price Anderson Act	The Price-Anderson Act, as amended by the Price-Anderson Act amendments of 1980
PURPA	Public Utility Regulatory Policies Act of 1978
SEC	Securities and Exchange Commission

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report:

Other

AFUDC	Allowance for Funds Used During Construction
Bondholders Committee or Committee	Officially Appointed Bondholders' Committee Representing Holders of EUA Power's Series B and Series C Secured Notes
CICs	Contingent Interest Certificates
Confirmation Date	The date of Confirmation of the Fifth Amended Plan of Reorganization as modified by the First Modification thereto
DIP Financing	Debtor-in-Possession Financing
Effective Date	Effective Date of the Fifth Amended Plan of Reorganization as modified by the First Modification thereto as filed by the Bondholders Committee
EWG	Exempt Wholesale Generator
FAS96	FASB Statement No. 96 - "Accounting for Income Taxes"
FAS109	FASB Statement No. 109 - "Accounting for Income Taxes"
IPPs	Independent Power Producers
JOA	Joint Owner Agreement Among Owners of the Seabrook Project
MW	Megawatt
NEPOOL	New England Power Pool
Participating Joint Owners	UI and CL&P, pursuant to the DIP financing
Plan	The Fifth Amended Plan of Reorganization as modified by the First Modification thereto
QFs	Qualifying cogeneration and small power production facilities
Seabrook Interest	The Company's right, title and interest in and to its 12.1324% interest in the Seabrook Project
Seabrook Project	Seabrook Nuclear Power Project
Seabrook Unit 1	Seabrook Nuclear Generating Station Unit 1
Seabrook Unit 2	Seabrook Nuclear Generating Station Unit 2
Secured Noteholders	Holders of the Secured Notes
Secured Notes	EUA Power's 17.50% Series B and Series C Secured Notes due May 15, 1993 and November 15, 1992, respectively.
Settlement Agreement	Settlement Agreement dated November 18, 1992, Among EUA Power, EUA and the Bondholders Committee

PART I

Item 1. BUSINESS

General

The Registrant, Great Bay Power Corporation (formerly known as EUA Power Corporation), is a New Hampshire corporation, incorporated in 1986, authorized by the NHPUC to engage in business as a public utility for the purposes of participating as a joint owner in the Seabrook Project, acquiring its 12.1% interest in the Seabrook Project and selling its share of the output of Seabrook Unit 1 for resale. The Company, organized as a wholly-owned subsidiary of EUA, became fully independent of EUA on February 5, 1993 in connection with the bankruptcy proceeding described below. The Company became a wholesale generating company when Seabrook Unit 1 commenced commercial operation on August 19, 1990.

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Bondholders Committees' Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega Advisers, Inc. ("Omega") or its designees to provide $35 million of equity financing for the Company (the "Omega Financing"). The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Fifth Amended Plan of Reorganization, as modified by the First Modification is hereinafter referred to as the "Plan." The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. (See

Bankruptcy Proceeding below for a discussion of the Company's bankruptcy proceeding and the Omega Financing.)

Seabrook Unit 1 is a 1,150 MW nuclear generating plant located in Seabrook, New Hampshire. The Company acquired its joint ownership interest in the Seabrook Project for approximately $174,000,000 in November 1986 from five New England electric utilities in independently negotiated transactions. At that time, construction of Seabrook Unit 1 was substantially completed. Because Seabrook Unit 2 had been cancelled, the Company assigned no value to it. On March 29, 1991, the Company announced that it had provided an impairment reserve in 1990 against its investment in Seabrook Unit 1. At December 31, 1993, the Company's net investment in Seabrook Unit 1, including nuclear fuel, was approximately $312 million.

The Company has no employees. John R. Stevens, president of EUA, serves as president and sole director of the Company at the request and subject to the direction of the Bondholders Committee. Mr. Stevens expects to resign both positions on the Effective Date. Since the Company's organization, EUA Service, a wholly owned subsidiary of EUA, has provided, or arranged for, various management and professional services. Pursuant to various Bankruptcy Court orders, EUA Service continues to provide similar services to the Company. Under the terms of the Settlement Agreement (as discussed below), EUA Service will continue to provide, at cost, certain services to the Company at the request of the Bondholders Committee for a period of not more than two years from the effective date of the Settlement Agreement. However, such services specifically exclude the marketing of the Company's entitlement in Seabrook Unit 1 on a long-term basis. The Company has agreed with UNITIL that an affiliate of UNITIL will replace EUA Service in providing various services on the Effective Date. In addition, the Company has entered into a contract with an affiliate of UNITIL pursuant to which that affiliate is marketing the Company's share of electricity from Seabrook Unit 1.

Bankruptcy Proceeding

Background:

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the federal Bankruptcy Code and has been conducting its business as a Debtor and Debtor-in-Possession under the provisions of the Bankruptcy Code. The Company filed such petition because the cash generated by short-term sales of electricity from its entitlement in Seabrook Unit 1 would have been insufficient to pay interest on its outstanding Secured Notes when interest became due on May 15, 1991 and the prospects for signing long-term power sales contracts prior to that date were minimal. The Company continues its efforts to market its entitlement to Seabrook Unit 1 under the direction of the Bondholders Committee.

Settlement Agreement:

On November 18, 1992, the Company, the Bondholders Committee and EUA entered into a Settlement Agreement which resolved certain adversary proceedings against EUA, brought, or threatened to be brought, by the Bondholders Committee including, (i) a claim for recovery of certain alleged preferential transfers in the aggregate amount of $38.5 million, plus interest;

(ii) a threatened claim for the recovery of $100 million plus treble damages arising from, among other things, certain alleged breaches of fiduciary duties by EUA, EUA Service and the officers and directors of the Company; and, (iii) certain matters arising out of tax sharing agreements between EUA, its subsidiaries, and the Company. The Settlement Agreement also provided for the payment of $20 million to the Company by EUA. The Settlement Agreement further provided for the relinquishment by EUA of its equity interest in the Company and all claims filed in Bankruptcy Court by EUA and its affiliates against the Company. These claims related primarily to obligations of the Company guaranteed and paid by EUA, including $21 million of Solid Waste Disposal Facility Revenue Bonds, issued by the New Hampshire Industrial Development Authority on behalf of the Company and other notes payable. The settlement of these claims was recorded as a deferred credit on the Company's 1992 Balance Sheet, pending the ultimate outcome of the Bankruptcy Proceeding. The Settlement Agreement became effective on December 30, 1992 at which time EUA paid $20 million to the Company. The Company used a substantial portion of the proceeds from the Settlement Agreement to repay amounts outstanding under the First Stipulation (as described below) and to pay reorganization expenses and other operating expenses. The Company redeemed all of its outstanding equity securities which were held by EUA, at no cost, on February 5, 1993. The redeemed shares have been classified as treasury stock on the Company's financial statements as of December 31, 1993 and 1992. As a result of the redemption, the Company is no longer part of the EUA System.

Under the Settlement Agreement, EUA reaffirmed its guarantee of up to $10 million of the Company's share of future decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. EUA had guaranteed this obligation in 1990 in order to secure the release to the Company of a $10 million fund established by the Company for the same purpose at the time the Company acquired its Seabrook Interest. Further, under the Settlement Agreement, all of the officers and directors of the Company (except Mr. Stevens) resigned and the Company changed its name to Great Bay Power Corporation. EUA now has no ownership interest in the Company.

Reorganization Plan:

The Bankruptcy Court confirmed the Bondholders Committees Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega or its designees to provide $35 million of equity financing for the Company. The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the Plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims pursuant to the Bonds and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. The holders of unsecured claims of less than $25,000, other than those unsecured claims resulting from the ownership of the Secured Notes, will be paid 50% of the amounts of their claims allowed by the Bankruptcy Court in cash on the Effective Date. The Plan requires that prior to the Effective Date the Bondholders Committee obtain the Omega Financing.

Although a bar date for all claims has been entered and passed, claims arising from the rejection of contracts or claims which the Bankruptcy Court permits to be filed notwithstanding the bar date may dilute the percentage of the unsecured claims held by the Secured Bondholders. All of the previously issued and outstanding equity securities of the Company have been redeemed by the Company. The CICs issued in connection with the Series B Notes or otherwise will be extinguished on the Effective Date. After the Effective Date, the equity of the Company will be represented by a single class of common stock. The Company will use good faith efforts to list its shares of common stock so that they will be tradeable on the American Stock Exchange or the NASDAQ National Market System.

The Bondholders Committee has appointed or will appoint agents to manage the Company's business and to market the Company's share of Seabrook electricity. During the period between the Confirmation of the Plan and the Effective Date, those agents are to report to the Bondholders Committee and, to the extent actions are to be taken outside of the ordinary course of business, such actions shall be subject to the approval of the Bankruptcy Court and regulatory bodies with jurisdiction under applicable law. John R. Stevens, president of EUA, expects to resign as president and director of the Company on the Effective Date. The Bondholders Committee has disclosed the names of two individuals proposed to serve on the Board of Directors (the New Board) of the Company after the Effective Date. The proposed two members of the New Board are John A. Tillinghast and Walter H. Goodenough. The Bondholders Committee is also considering other candidates to serve as members of the New Board. The persons who will serve on the New Board will be finally determined before the Effective Date. The New Board will take office upon the Effective Date. The New Board will serve until its members resign or are replaced in accordance with New Hampshire corporate law and the requirements of the Company's charter and by-laws.

The effectiveness of the Plan is conditioned upon obtaining plan of reorganization financing and approvals from various regulatory agencies including the NRC. The Company has obtained the approval of the NRC, provided the Company obtains plan of reorganization financing. The Company cannot predict whether it will be able to obtain plan of reorganization financing or whether the plan, or any other plan if filled, will be approved by the various regulatory agencies having jurisdiction.

DIP Financing:

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses including, without limitation, operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA could adversely affect its entitlement in Unit 1. At current market prices, the cash generated by such electricity sales continues to be less than the Company's on-going cash requirements.

On August 29, 1991, the Bankruptcy Court approved a Stipulation and Consent Order (the First Stipulation) with respect to DIP Financing to be provided by certain joint owners of Seabrook for the benefit of the Company. The First Stipulation was entered into by the Company and CL&P and UI (the Participating Joint Owners), two of the other eleven joint owners of the Seabrook Project, as well as the Bondholders Committee. The First Stipulation was also approved by the NHPUC and the SEC under the 1935 Act.

On July 21, 1992, the Bankruptcy Court issued a procedural order permitting an extension of the First Stipulation. For the period after September 30, 1992 until March 5, 1993, the procedural order permitted continued debtor-in-possession financing on a month-to-month basis at the sole discretion of the Participating Joint Owners terminable on 30 days notice. The Bankruptcy Court issued a second procedural order on September 8, 1992 increasing to $22 million from $15 million the amount of advances outstanding at any one time permitted under the First Stipulation. The Participating Joint Owners continued to advance funds under the First Stipulation, as amended, until the amounts advanced thereunder were repaid with the proceeds of the Company's Settlement Agreement with EUA. The First Stipulation expired on March 5, 1993.

A second stipulation was entered into by the Company and the Participating Joint Owners and was approved by the Bankruptcy Court and various regulatory authorities. However, that stipulation did not become effective, and on March 5, 1993, the Company and the Participating Joint Owners entered into a third stipulation (the Third Stipulation) which was approved by the Bankruptcy Court.

The Third Stipulation provides that the Participating Joint Owners shall provide up to a maximum of $20 million in advances to the Company to enable the Company to pay its <u>pro rata</u> share of the Seabrook Project's operating expenses, expenses of the Company in connection with its Chapter 11 proceedings and certain other costs of operation of the Company. Pursuant to the Third Stipulation, the advances made by the Participating Joint Owners bear an interest rate equal to the prime rate of The First National Bank of Boston plus 7% per annum. The Third Stipulation provides the Participating Joint Owners with a priority lien on all the Company's assets, which lien has priority over the Bondholders' mortgage. The Third Stipulation further provides that in the event of a default thereunder, the Participating Joint Owners are entitled to purchase the Company's Seabrook Interest for 75% of the lesser of fair market value or book value and to apply all or part of the amounts owing under the Third Stipulation against the purchase price. The Third Stipulation terminates on the earliest to occur of (a) July 1, 1994, (b) the Effective Date or the closing of a sale of all or substantially all of the Company's assets or business, and (c) an event of default under the terms of the Third Stipulation. The Company is in default of the Third Stipulation for, among other reasons, failure to obtain financing for the Plan by the date required in the Third Stipulation. Although the Company has been in default since November 1, 1993, the Participating Joint Owners have continued to provide financing pursuant to the Third Stipulation. There is, however, no assurance that they will continue to do so. As of March 25, 1994, outstanding advances under the Third Stipulation were approximately $2.2 million in the aggregate.

If the Plan is confirmed by the Bankruptcy Court and the Omega Financing is obtained, the Company will repay amounts owing under the Third Stipulation out of the proceeds of the Omega Financing. The Company cannot predict whether the Plan will be confirmed or the Omega Financing obtained.

Other Matters:

The Company's reorganization expenses are subject to approval by the Bankruptcy Court. For the period March 1, 1991 through August 31, 1993, professionals have submitted fees and expenses in the amount of approximately $5.9 million to the Bankruptcy Court for its approval, and the Bankruptcy Court has provisionally authorized, subject to its review at the conclusion of the Chapter 11 proceeding, payments of approximately $4.5 million. The Company has paid amounts provisionally authorized by the Bankruptcy Court, and those are reflected on the Company's Statement of Loss during the period in which they have been paid.

Since August 31, 1993, no hearings on approval of reorganization expenses have been held and no requests for allowance for such expenses have been made. According to the Supplemental Disclosure Statement, the Bondholders Committee has budgeted reorganization expenses payable on closing of the Omega Financing and subject to Bankruptcy Court approval of $4.5 million.

Under Chapter 11, certain claims against the Company in existence prior to the filing of the petition for relief under the Bankruptcy Code are stayed while the Company continues business operations as debtor-in-possession. These claims are reflected in the Company's Balance Sheet as of December 31, 1993 and December 31, 1992 as "Liabilities Subject to Compromise." Additional claims (Liabilities Subject to Compromise) may arise subsequent to the filing date resulting from rejection of executory contracts and from the determination by the Bankruptcy Court (or agreed to by parties in interest) of allowed contingent and disputed claims. Enforcement of claims secured by certain of the Company's assets (secured claims) also are stayed, although the holders of such claims have the right to move the court for relief from the stay. Secured claims, principally the Secured Notes, are secured by an interest in certain Seabrook Project assets of the Company, principally realty and personalty.

EUA Power Debt:

The current face amount of principal and accrued interest to February 28, 1991 on the Company's Secured Notes is $279,597,200 and $14,126,174, respectively. The Secured Notes are collateralized by a security interest in the Company's 12.1% ownership interest in the realty and personalty of the Seabrook Project. Early in the Chapter 11 proceeding, the Company raised the issue of whether the Secured Noteholders are also secured by the Company's "entitlement" to electricity from Seabrook Unit 1. In light of the Plan, this issue did not need to be resolved in the Chapter 11 case. As a result of the bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued. All of the Secured Notes will be converted into common stock of the Company on the Effective Date.

The Company also has outstanding 180,000 CICs evidencing the right to receive additional payments contingent upon, and measured by, the Company's income in certain years following the commercial operation of Seabrook Unit 1. Under the Plan, the CICs will be extinguished on the Effective Date. Such Secured Notes and CICs are solely the obligation of the Company and are not guaranteed by EUA or any other person (see Reorganization Plan above).

Marketing

The Company, under the direction of the Bondholders Committee, is currently seeking to enter into long-term power contracts to realize the long-term value of its interest in the Seabrook Project. The Company intends to continue its marketing efforts which have consisted of both direct negotiations with utilities and participation in utility sponsored supply bidding processes. The Company's marketing efforts are being provided by an affiliate of Unitil under the supervision of the Bondholders Committee.

The Company has entered into a contract for the sale of approximately 10MW of its entitlement in Seabrook Unit 1 (See Power Purchase Agreement and Power Purchase Option below). However, economic conditions in the Northeast, the availability of competing long-term power supplies and the bidding requirements for power contracts being implemented by various state utility commissions continue to adversely affect the Company's ability to enter into long-term sales contracts. Consequently, the Company is unable to predict when, if ever, the Company will be able to enter into additional long-term purchased power contracts.

Power Purchase Agreement and Power Purchase Option

The Company has entered into an agreement (the Power Purchase Agreement) with UNITIL Power Corporation (UNITIL Power), a wholly owned subsidiary of UNITIL, which provides for the Company to sell to UNITIL Power approximately 0.9% of the power generated by Seabrook Unit 1 (approximately 10 MW) and allocable to the Company at prices significantly above those currently available in the spot-market, where the Company is otherwise selling its electricity. The Power Purchase Agreement has an initial term which commenced on May 1, 1993 and extends through October 31, 2010. From the commencement date of sales through October 31, 1993, the price of power under the Power Purchase Agreement was 5.0 cents per kilowatthour (kWh), with formula increases at less than inflation thereafter. The Power Purchase Agreement also provides UNITIL Power with the option to extend the Power Purchase Agreement for an additional 12 years.

To provide the Company with needed near-term revenue and cash flow while spot-market prices are low, the Power Purchase Agreement is front-end loaded whereby UNITIL Power will pay more in real terms in the early years of the Agreement and lesser amounts in later years. This structure is not unusual for power purchase contracts, and will result in an increase in the Company's revenues above the existing spot-market price. The amount of this "overpayment" by UNITIL Power in the early years of the Power Purchase Agreement is quantified in a "Balance Account", which increases annually to $4.1 million in 1998, then decreases annually, reaching zero in 2001. If the Power Purchase Agreement terminates when there is a positive amount in the Balance Account, the Company is obligated to pay that amount to UNITIL Power.

To secure the obligation of the Company under the Power Purchase Agreement to repay to UNITIL Power the amounts in the Balance Account, the Power Purchase Agreement grants UNITIL Power a mortgage on the Company's Seabrook Interest. This mortgage granted to UNITIL Power is junior only to the existing mortgage on the Seabrook Interest granted pursuant to the Third Stipulation and any successor first mortgage financing up to a maximum amount of $80,000,000. The Power Purchase Agreement further provides that UNITIL's second mortgage will rank pari passu with other mortgages that may hereafter be granted to other purchasers of power from the Company to secure similar obligations, provided that the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest does not exceed $80,000,000 and provided that the combined total of all second mortgages on the Seabrook Interest does not exceed the sum of (a) $80,000,000 less the total amount of the Company's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

The Power Purchase Agreement will also provide that the Company must pay UNITIL Power "benefit of the bargain" damages in the event that the Power Purchase Agreement is terminated due to a default by the Company. To secure the Company's obligations under this provision, the Power Purchase Agreement grants UNITIL Power a third mortgage on the Seabrook Interest junior to the first mortgage and the second mortgages described above, but senior to the Bondholders' Mortgage. The Power Purchase Agreement provides that such third mortgage may be pari passu with mortgages securing similar obligations to other purchasers of power from the Company for the reasons set forth above.

In addition to the Power Purchase Agreement, the Company also has entered into an agreement (the Power Purchase Option Agreement) with UNITIL Power under which the Company will grant UNITIL Power the option to purchase, in addition to the purchases by UNITIL Power under the Power Purchase Agreement, approximately 1.3% of the power generated by Seabrook Unit 1 (approximately 15 MW) and allocable to the Company at prices significantly above those currently available in the spot market. If UNITIL Power exercises this option, the Power Purchase Option Agreement would serve as an additional power purchase agreement with sales taking place under it from November 1, 1998 through October 31, 2018. The purchase price under the Power Purchase Option Agreement will be 6.5 cents per kWh, adjusted to reflect inflation from May 1, 1993 to November 1, 1998, with annual increases thereafter in accordance with inflation to the extent inflation exceeds 1% during the applicable year.

UNITIL Power will be required to exercise its option under the Power Purchase Option Agreement on or before the earlier of (a) October 31, 1996, and (b) 30 days after the first date on which the Company is prepared to commit to sell, for a minimum of 10 years, all or any part of the last remaining 15 MW of electricity from Seabrook Unit 1 to which the Company is entitled. The Power Purchase Option Agreement also requires UNITIL Power to purchase up to 15 MW of electricity from the Company, at the discretion of the Company, on a month-to-month basis, during the interim period between the date on which UNITIL Power exercises its option (if it does so) and November 1, 1998, when purchases begin under the terms of the Power Purchase Option Agreement. The purchase price for electricity during this option period will be determined on a monthly basis at $3.00 less than UNITIL Power's actual marginal cost per megawatthour in the applicable month.

In contrast to the Power Purchase Agreement, the Power Purchase Option Agreement does not provide for a Balance Account.

Competition

The Company is facing new sources of competition primarily as a result of PURPA, the Energy Act, and other policies being implemented by state regulators relating to the solicitation of competitive proposals for new generation sources. Non-utility wholesale generators, generally known as independent power producers or IPPs, are subject to FERC regulations under the Federal Power Act as well as various other federal, state and local regulators. However, PURPA was intended, among other things, to promote national energy independence and diversification of energy supply and to improve the overall efficiency of energy usage. PURPA created a new class of non-utility power generation facilities called QFs. PURPA allows QFs to sell power generated by the QFs to local utilities at specified rates based on each utility's avoided cost. In order to further promote completion in energy supply, the Energy Act established a new class of non-utility generators, generally referred to as EWGs, which are exempt from the 1935 Act. The Company is an EWG. Also, various states have implemented regulations which require utilities to integrate least-cost planning with competitive proposals to meet requirements for new generation. The Company is competing with New England and New York utilities and with QFs, EWGs and IPPs as it markets its wholesale power to other electric utilities. The Company may face increased competition, primarily based on price, from such sources in the future.

The Company is a party to the NEPOOL Agreement and is a member of NEPOOL. NEPOOL is open to all investor-owned, municipal and cooperative electric utilities in New England that are connected to the New England power grid under an agreement which provides for coordinated planning of future facilities as well as the operation of nearly 100% of existing generating capacity in New England and of related transmission facilities as if they were one system. The NEPOOL agreement imposes obligations concerning generating capacity reserves and the right to use major transmission lines, and provides for central dispatch of the generating capacity of the pool's members with the objective of achieving economical use of the region's facilities. Pursuant to the NEPOOL agreement, interchange sales to NEPOOL are made at a price approximately equal to the fuel cost for generation without contribution to the support of fixed charges. Because of its participation in NEPOOL, the Company's operating revenues and costs are affected to some extent by the operations of other members.

Construction Program

The Company's cash construction expenditures for 1994, 1995 and 1996, as set forth below, are estimated to total $18.5 million (including nuclear fuel expenditures).

GREAT BAY POWER CONSTRUCTION PROGRAM
(Thousands of Dollars)

	1994	1995	1996	3-Yr Total
Seabrook Unit 1 Construction	$ 4,290	$ 7,002	$ 7,160	$18,452

Cash construction and nuclear fuel expenditures for the year ended December 31, 1993 were approximately $6.9 million.

Nuclear Power Issues

Like other nuclear generating facilities, the Seabrook Project is subject to extensive regulation by the NRC. The NRC is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health, safety, environmental and anti-trust matters.

The NRC has promulgated numerous requirements affecting safety systems, fire protection, emergency response planning and notification systems, and other aspects of nuclear plant construction, equipment and operation. The Company has been, and may be, affected to the extent of its proportionate share by the cost of any such modifications to Seabrook Unit 1.

Nuclear units in the United States have been subject to widespread criticism and opposition. Some nuclear projects have been cancelled following substantial construction delays and cost overruns as the result of licensing problems, unanticipated construction defects and other difficulties. Various groups have by litigation, legislation and participation in administrative proceedings sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste. In the event of a shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. The cost of such decommissioning, depending on the circumstances, could substantially exceed the owners' investment at the time of cancellation.

Public controversy concerning nuclear power could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

The Price-Anderson Act provides, among other things, that the liability for damages resulting from a nuclear incident would not exceed an amount which at present is about $9.2 billion. Under the Price-Anderson Act, prior to operation of a nuclear reactor, the licensee is required to insure against this exposure by purchasing the maximum amount of insurance available from private sources (currently $200 million) and to maintain the insurance available under a mandatory industry-wide retrospective rating program. Should an individual licensee's liability for an incident exceed $200 million, the difference between such liability and the overall maximum liability, currently about $9.2 billion, will be made up by the retrospective rating program. Under such a program, each owner of an operating nuclear facility may be assessed a retrospective premium of up to a limit of $79.3 million (which shall be adjusted for inflation at least every five years) for each reactor owned in the event of any one nuclear incident occurring at any reactor in the United States, with provision for payment of such assessment to be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. The Company would be obligated to pay its proportionate share of any such assessment.

Joint owners of nuclear projects are also subject to the risk that one of their number may be unable or unwilling to finance its share of the project's costs, thus jeopardizing continuation of the project. On May 6, 1991, New Hampshire Electric Cooperative, Inc., a 2.2% owner of the Seabrook Project, announced that it had filed for Chapter 11 bankruptcy protection. A reorganization plan, filed by the New Hampshire Electric Cooperative with the Bankruptcy Court in September, 1991 and revised in January, 1992 was approved by the Bankruptcy Court in March 1992 and approved by the NHPUC on October 5, 1992. All appeals of the NHPUC order approving the reorganization have been resolved in NHEC's favor and the effective date of the plan occurred on December 1, 1993.

Nuclear Fuel and Nuclear Plant Decommissioning:

The Seabrook Project joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. The owners and lead participants of United States nuclear units have entered into contracts with the DOE for disposal of spent nuclear fuel in accordance with the NWPA. The NWPA requires (subject to various contingencies) that the federal government design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such wastes and fuel. The NWPA specifies that the DOE provide for the disposal of such wastes and spent nuclear fuel starting in 1998. Objections on environmental and other grounds have been asserted against proposals for storage as well as disposal of spent fuel. The DOE anticipates that a permanent disposal site for spent fuel will be ready to accept fuel for storage on or before 2010. However, the NRC, which must license the site, stated only that a permanent repository will become available by the year 2025. At the Seabrook Project there is on-site storage capacity which, with minimal capital expenditures, should be sufficient for twenty years or until the year 2010. No near-term capital expenditures are anticipated to deal with any increase in storage requirements after 2010.

The estimated cost to decommission Seabrook Unit 1, based on a study performed for the lead owner of the Plant is approximately $351 million in 1993 dollars. The Company's share of that amount is approximately $42.6 million, or 12.1%. In 1993, the Company paid approximately $895,000 in decommissioning expenses.

The agreements of purchase and sale under which the Company purchased its Seabrook Interest required the Company to establish a fund of $10 million to secure payment of part of its share of the decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. In May 1990, EUA guaranteed this obligation and the entire fund was released to the Company. Under the Settlement Agreement EUA reaffirmed this guaranty. (See <u>Bankruptcy Proceeding</u> - Settlement Agreement above.)

Seabrook Unit 2:

The Company also has a 12.1% ownership interest in Seabrook Unit 2 to which it has assigned no value. On November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been cancelled in 1984, voted to dispose of the Unit. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. Plans regarding disposition of Seabrook Unit 2 are now under consideration, but have not been finalized and approved. The Company is unable, therefore, to estimate the costs for which it would be responsible in connection with the disposition of Seabrook Unit 2. Monthly charges are required to be paid by the Company with respect to Seabrook Unit 2 in order to preserve and protect its components and various warranties.

Public Utility Regulation

The Company is subject to regulation by the NHPUC in many respects including the issuance of securities, contracts with affiliates, forms of accounts, transfers of utility properties and other matters but excluding the rates charged for sales of electricity at wholesale.

The Company is no longer subject to the jurisdiction of the SEC under the 1935 Act as a result of the redemption by the Company of its outstanding equity securities held by EUA and as a result of its status as an EWG.

The Company is also subject to the jurisdiction of FERC under Parts II and III of the Federal Power Act. That jurisdiction includes, among other things, rates for sales for resale, interconnection of certain facilities, accounts, service and property records.

(See Nuclear Power Issues with respect to regulation of nuclear facilities by the NRC and see Nuclear Fuel and Nuclear Plant Decommissioning with respect to the disposal of spent nuclear fuel. See also Environmental Regulation and Energy Policy, below.)

Environmental Regulation

The Company, like other electric utilities, is subject to standards administered by federal, state and local authorities with respect to the siting of facilities and associated environmental factors. The EPA, and certain state and local authorities, have jurisdiction over releases of pollutants, contaminants and hazardous substances into the environment and have broad authority in connection therewith including the ability to require installation of pollution control devices and remedial actions. The NRC has promulgated a variety of standards to protect the public from radiological pollution caused by the normal operation of nuclear generating facilities.

In some environmental areas the NRC and the EPA have overlapping jurisdiction. Thus, NRC regulations are subject to all conditions imposed by the EPA and a variety of federal environmental statutes, including obtaining permits for the discharge of pollutants (including heat) into the nation's navigable waters. In addition, the EPA has established standards, and is in the process of reviewing existing standards, for certain toxic air pollutants, including radionuclides, under the Clean Air Act which apply to NRC-licensed facilities. The effective date for the new radionuclide standards has been stayed as to nuclear generating units. The EPA has also promulgated environmental radiation protection standards for nuclear power plants which regulate the doses of radiation received by the general public.

The NWPA provides for development by the federal government of facilities for the disposal or permanent storage of civilian nuclear waste. (See Nuclear Fuel and Nuclear Plant Decommissioning.) The NRC has also promulgated regulations regarding the disposal of nuclear waste materials designed to protect the public from radiological dangers.

Environmental regulation of nuclear facilities may result in significant increases in capital and operating costs, in delays or cancellation of construction of planned improvements, or in modification or termination of existing facilities.

Energy Policy

The Energy Act deals with many aspects of national energy policy and includes important changes for electric utilities and registered holding companies. It is not possible to predict the impact which the Energy Act and the rules and regulations which will be promulgated by various regulatory agencies pursuant to the Energy Act will have on the Company. Certain provisions of the Energy Act will increase competition in the generation of electricity. One of the more significant provisions of the Energy Act creates a new class of generation companies exempt from the 1935 Act, which sell exclusively at wholesale, called EWGs. The Company is an EWG. The Energy Act also grants FERC new authority to mandate transmission access for QFs, EWGs and traditional utilities.

It is also not possible to predict the timing or content of future energy policy legislation and the significance of such legislation to the Company. Various issues not addressed by the Energy Act, including regional planning and transmission arrangements, could be addressed in future legislation.

Item 2. PROPERTIES

The Company's principal asset is its 12.1324% joint ownership interest in the Seabrook Project. The Seabrook Project is a nuclear-fueled, steam electricity, generating plant located in Seabrook, New Hampshire, which was planned to have two Westinghouse pressurized water reactors, Seabrook Unit 1 and Seabrook Unit 2 (each with a rated capacity of 1,150 megawatts), utilizing ocean water for condenser cooling purposes. Seabrook Unit 1 entered commercial services on August 19, 1990. Seabrook Unit 2 has been cancelled. The Company is required to pay its share (i.e., the same percentage as the percentage of its ownership and its entitlement to the output) of all of the costs of the Seabrook Project including fixed costs (whether or not Seabrook Unit 1 is operating), operating costs, costs of additional construction or modification, costs associated with condemnation, shutdown, retirement, or decommissioning of the Seabrook Project, and certain transmission charges.

Item 3. LEGAL PROCEEDINGS

Bankruptcy Proceeding

On February 28, 1991, the Company filed a voluntary petition for protection under Chapter 11 of the federal Bankruptcy Code. A plan of reorganization filed by the Bondholders Committee was confirmed on March 5, 1993. That Plan has been modified and will be resubmitted to the creditors of the Company for their approval. For a general discussion, See Item 1, BUSINESS - Bankruptcy Proceeding.

SEC Review

In January of 1991, the SEC's Division of Corporation Finance commenced a review of the Company's Annual Report on Form 10-K for the year ended December 31, 1989 and subsequent Quarterly Reports on Form 10-Q. The Company submitted written responses to all of the inquiries made by the Division of Corporate Finance. In May of 1991, the Company was informed by the SEC's Division of Enforcement that it would conduct an informal review with respect to certain issues addressed by the Division of Corporate Finance principally relating to the accounting for the capitalized financing costs related to the Company's investment in Seabrook Unit 1 and the effect which recording such amounts had on reported earnings for the three year period ended December 31, 1990. The Company informed the Division of Enforcement that it would cooperate with the informal inquiry and in July of 1991 the Company completed its responses to the Division of Enforcement's initial inquiries. The Company has received no communications from the Division of Enforcement since the Company completed its responses in July, 1991.

The Company restated its financial statements with respect to the amount of AFUDC recorded in 1988, 1989 and the first three quarters of 1990 which it believes addresses several issues raised by the SEC. The Company cannot predict the outcome of the SEC's review. The SEC could require that the Company further restate its financial statements for 1990, 1989 or 1988, or for any quarterly period during such years. The ultimate outcome of this matter cannot presently be determined and, accordingly, no provision for any adjustment that may result from its outcome has been made in the 1990 financial statements of the Company. The Company continues to believe that its financial statements (as previously restated) were prepared in accordance with generally accepted accounting principles and presented fairly the financial position and results of operations of the Company.

Other Proceedings

On January 8, 1992, the Massachusetts Municipal Wholesale Electric Cooperative and its member municipalities, all of which are members of NEPOOL, filed a suit in Massachusetts Superior Court against the investor-owned utilities that are also members of NEPOOL. The suit alleges damages by NEPOOL's establishment of minimum size requirements for generating units designated as pool-planned generating units. The suit names as defendants members of NEPOOL, including the Company. Management cannot predict the ultimate outcome of this proceeding at this time. Discovery has not begun, pending resolution of certain procedural matters. The FERC initiated an action when the EUA subsidiaries and other participants filed an amendment to the NEPOOL Agreement with the FERC that concerns many of the issues raised in the Massachusetts litigation. The plaintiffs in the Massachusetts litigation and one other participant have objected to the amendment, and have sought to prevent or delay its effectiveness. The FERC has not yet determined whether or when it will hold hearings on this matter. Management cannot predict the ultimate outcome of this proceeding at this time.

In June 1991, the State of New Hampshire imposed a Nuclear Station Property Tax applicable only to the Seabrook Project. The Company paid its share of the tax, aggregating $4.2 million through December 31, 1992. In October 1991 the Attorneys General of Connecticut, Massachusetts and Rhode Island petitioned the United States Supreme Court in an original jurisdiction case for a determination of the legality of the tax, and in January 1992 the Supreme Court agreed to take the case. The parties to the litigation and other Joint Owners of Seabrook entered into a Settlement Agreement on April 13, 1993. In general, the terms of the Settlement Agreement significantly reduced nuclear station property taxes payable by the Company. In addition, under the terms of the Settlement Agreement, certain of the prior payments of the tax by the Company will be permitted to be credited against future taxes due. The Bankruptcy Court has approved the Settlement Agreement with respect to the Company.

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

None.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

On February 5, 1993, the Company redeemed all of its outstanding equity securities previously held by EUA pursuant to the terms of the Settlement Agreement. The Company reflects this balance as Treasury Stock on the Statement of Capitalization since December 31, 1992.

No dividends have ever been paid or declared on the Company's equity securities.

Item 6. SELECTED FINANCIAL DATA

The selected financial data for the year ended December 31, 1989 has been restated from amounts previously reported.

(Dollars In Thousands)	For the year Ended December 31, 1993	1992	1991	1990	1989
Operating Revenues	$ 24,620	$ 23,027	$ 20,919	$ 10,499	$
Net (Loss) Income	(18,478)	(47,468)	(19,792)	(74,505)	(2,983)
Total Assets	337,616	346,137	359,058	365,920	413,195
Capitalization:					
Long-Term Debt (excluding current maturities)			180,000	300,597	279,597
Common Equity	(148,828)*	(130,350)*	(82,882)	(63,090)	11,417
Cumulative Convertible Preferred Stock	63,090*	63,090*	63,090	63,090	60,790
Total Capitalization	$(85,738)	$(67,260)	$160,208	$300,597	$351,804

* Balances include Paid-In Capital - Treasury Stock of $10,000 and $63,090,000 for Common Equity and Cumulative Convertible Preferred Stock, respectively.

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

Overview:

Great Bay operates as a public utility in the state of New Hampshire. The Company was organized for the purpose of acquiring a 12.1% ownership interest in the Seabrook Project and selling, in the wholesale market its share of the electricity generated by Seabrook Unit 1.

On February 28, 1991, the Company filed a voluntary petition in the federal Bankruptcy Court for protection under Chapter 11 of the federal Bankruptcy Code and has been conducting its business as a Debtor and a Debtor-In-Possession under the provisions of the Bankruptcy Code.

Settlement Agreement:

On November 18, 1992, the Company, the Bondholders Committee and EUA entered into a Settlement Agreement which resolved certain adversary proceedings against EUA, brought, or threatened to be brought, by the Bondholders Committee including, (i) a claim for recovery of certain alleged preferential transfers in the aggregate amount of $38.5 million, plus interest; (ii) a threatened claim for the recovery of $100 million plus treble damages arising from, among other things, certain alleged breaches of fiduciary duties by EUA, EUA Service and the officers and directors of the Company; and, (iii) certain matters arising out of tax sharing agreements between EUA, its subsidiaries, and the Company. The Settlement Agreement also provided for the payment of $20 million to the Company by EUA. The Settlement Agreement further provided for the relinquishment by EUA of its equity interest in the Company and all claims filed in Bankruptcy Court by EUA and its affiliates against the Company. These claims related primarily to obligations of the Company guaranteed and paid by EUA, including $21 million of Solid Waste Disposal Facility Revenue Bonds, issued by the New Hampshire Industrial Development Authority on behalf of the Company and other notes payable. The settlement of these claims was recorded as a deferred credit on the Company's 1992 Balance Sheet, pending the ultimate outcome of the Bankruptcy Proceeding. The Settlement Agreement became effective on December 30, 1992 at which time EUA paid $20 million to the Company. The Company used a substantial portion of the proceeds from the Settlement Agreement to repay amounts outstanding under the First Stipulation (as described below) and to pay reorganization expenses and other operating expenses. The Company redeemed all of its outstanding equity securities which were held by EUA, at no cost, on February 5, 1993. The redeemed shares have been classified as treasury stock on the Company's financial statements as of December 31, 1992. As a result of the redemption, the Company no longer part of the EUA System.

Under the Settlement Agreement, EUA reaffirmed its guarantee of up to $10 million of the Company's share of future decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. EUA had guaranteed this obligation in 1990 in order to secure the release to the Company of a $10 million fund established by the Company for the same purpose at the time the Company acquired its Seabrook Interest. Further, under the Settlement Agreement, all of the officers and directors of the Company (except Mr. Stevens) resigned and the Company changed its name to Great Bay Power Corporation. EUA now has no ownership interest in the Company.

Reorganization Plan:

The Bankruptcy Court confirmed the Bondholders Committees Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega or its designees to provide $35 million of equity financing for the Company. The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the Plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims pursuant to the Bonds and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. The holders of unsecured claims of less than $25,000, other than those unsecured claims resulting from the ownership of the Secured Notes, will be paid 50% of the amounts of their claims allowed by the Bankruptcy Court in cash on the Effective Date. The Plan requires that prior to the Effective Date the Bondholders Committee obtain the Omega Financing.

Although a bar date for all claims has been entered and passed, claims arising from the rejection of contracts or claims which the Bankruptcy Court permits to be filed notwithstanding the bar date may dilute the percentage of the unsecured claims held by the Secured Noteholders. All of the previously issued and outstanding equity securities of the Company have been redeemed by the Company. The CICs issued in connection with the Series B Notes or otherwise will be extinguished on the Effective Date. After the Effective Date, the equity of the Company will be represented by a single class of common stock. The Company will use good faith efforts to list its shares of common stock so that they will be tradeable on the American Stock Exchange or the NASDAQ National Market System.

The Bondholders Committee has appointed or will appoint agents to manage the Company's business and to market the Company's share of Seabrook electricity. During the period between the Confirmation of the Plan and the Effective Date, those agents are to report to the Bondholders Committee and, to the extent actions are to be taken outside of the ordinary course of business, such actions shall be subject to the approval of the Bankruptcy Court and regulatory bodies with jurisdiction under applicable law. John R. Stevens, president of EUA, expects to resign as president and director of the Company on the Effective Date. The Bondholders Committee has disclosed the names of two individuals proposed to serve on the Board of Directors (the New Board) of the Company after the Effective Date. The proposed two members of the New Board are John A. Tillinghast and Walter H. Goodenough. The Bondholders Committee is also considering other candidates to serve as members of the New Board. The persons who will serve on the New Board will be finally determined before the Effective Date. The New Board will take office upon the Effective Date. The New Board will serve until its members resign or are replaced in accordance with New Hampshire corporate law and the requirements of the Company's charter and by-laws.

The effectiveness of the Plan is conditioned upon obtaining plan of reorganization financing and approvals from various regulatory agencies including the NRC. The Company has obtained the approval of the NRC, provided the Company obtains plan of reorganization financing. The Company cannot predict whether it will be able to obtain plan of reorganization financing or whether the plan, or any other plan if filled, will be approved by the various regulatory agencies having jurisdiction.

Power Purchase Agreement and Power Purchase Option

The Company has entered into an agreement (the Power Purchase Agreement) with UNITIL Power Corporation (UNITIL Power), a wholly owned subsidiary of UNITIL, which provides for the Company to sell to UNITIL Power approximately 0.9% of the power generated by Seabrook Unit 1 (approximately 10 MW) and allocable to the Company at prices significantly above those currently available in the spot-market, where the Company is otherwise selling its electricity. The Power Purchase Agreement has an initial term which commenced on May 1, 1993 and extends through October 31, 2010. From the commencement date of sales through October 31, 1993, the price of power under the Power Purchase Agreement was 5.0 cents per kilowatthour (kWh), with formula increases at less than inflation thereafter. The Power Purchase Agreement also provides UNITIL Power with the option to extend the Power Purchase Agreement for an additional 12 years.

To provide the Company with needed near-term revenue and cash flow while spot-market prices are low, the Power Purchase Agreement is front-end loaded whereby UNITIL Power will pay more in real terms in the early years of the Agreement and lesser amounts in later years. This structure is not unusual for power purchase contracts, and will result in an increase in the Company's revenues above the existing spot-market price. The amount of this "overpayment" by UNITIL Power in the early years of the Power Purchase Agreement is quantified in a "Balance Account", which increases annually to $4.1 million in 1998, then decreases annually, reaching zero in 2001. If the Power Purchase Agreement terminates when there is a positive amount in the Balance Account, the Company is obligated to pay that amount to UNITIL Power.

To secure the obligation of the Company under the Power Purchase Agreement to repay to UNITIL Power the amounts in the Balance Account, the Power Purchase Agreement grants UNITIL Power a mortgage on the Company's Seabrook Interest. This mortgage granted to UNITIL Power is junior only to the existing mortgage on the Seabrook Interest granted pursuant to the Third Stipulation and any successor first mortgage financing up to a maximum amount of $80,000,000. The Power Purchase Agreement further provides that UNITIL's second mortgage will rank pari passu with other mortgages that may hereafter be granted to other purchasers of power from the Company to secure similar obligations, provided that the maximum amount of indebtedness secured by the first mortgage on the Seabrook Interest does not exceed $80,000,000 and provided that the combined total of all second mortgages on the Seabrook Interest does not exceed the sum of (a) $80,000,000 less the total amount of the Company's debt then outstanding which is secured by a first mortgage plus (b) $57,000,000.

The Power Purchase Agreement will also provide that the Company must pay UNITIL Power "benefit of the bargain" damages in the event that the Power Purchase Agreement is terminated due to a default by the Company. To secure the Company's obligations under this provision, the Power Purchase Agreement grants UNITIL Power a third mortgage on the Seabrook Interest junior to the first mortgage and the second mortgages described above, but senior to the Bondholders' Mortgage. The Power Purchase Agreement provides that such third mortgage may be pari passu with mortgages securing similar obligations to other purchasers of power from the Company for the reasons set forth above.

In addition to the Power Purchase Agreement, the Company also has entered into an agreement (the Power Purchase Option Agreement) with UNITIL Power under which the Company will grant UNITIL Power the option to purchase, in addition to the purchases by UNITIL Power under the Power Purchase Agreement, approximately 1.3% of the power generated by Seabrook Unit 1 (approximately 15 MW) and allocable to the Company at prices significantly above those currently available in the spot market. If UNITIL Power exercises this option, the Power Purchase Option Agreement would serve as an additional power purchase agreement with sales taking place under it from November 1, 1998 through October 31, 2018. The purchase price under the Power Purchase Option Agreement will be 6.5 cents per kWh, adjusted to reflect inflation from May 1, 1993 to November 1, 1998, with annual increases thereafter in accordance with inflation to the extent inflation exceeds 1% during the applicable year.

UNITIL Power will be required to exercise its option under the Power Purchase Option Agreement on or before the earlier of (a) October 31, 1996, and (b) 30 days after the first date on which the Company is prepared to commit to sell, for a minimum of 10 years, all or any part of the last remaining 15 MW of electricity from Seabrook Unit 1 to which the Company is entitled. The Power Purchase Option Agreement also requires UNITIL Power to purchase up to 15 MW of electricity from the Company, at the discretion of the Company, on a month-to-month basis, during the interim period between the date on which UNITIL Power exercises its option (if it does so) and November 1, 1998, when purchases begin under the terms of the Power Purchase Option Agreement. The purchase price for electricity during this option period will be determined on a monthly basis at $3.00 less than UNITIL Power's actual marginal cost per megawatthour in the applicable month.

In contrast to the Power Purchase Agreement, the Power Purchase Option Agreement does not provide for a Balance Account.

Comparison of Financial Results

The Company reported a net loss in each of the last three years as follows: $9.4 million in 1993, $47.5 million in 1992 and $19.8 million in 1991. These losses are primarily due to short-term power sales of the Company's entitlement from Seabrook Unit 1 at prices substantially below actual operations, maintenance and capital related costs.

The 1993 net loss was $38.1 million less than the 1992 net loss primarily due to the 1992 reversal of certain tax assets because of the uncertainty of the availability of those assets to the Company. This reversal significantly increased 1992's provision for deferred taxes contributing to the larger net loss reported by the Company in 1992. Also, the Company began recognizing deferred tax assets relating to net operating losses subsequent to the change in ownership of the Company which occurred on February 5, 1993.

Operating Revenues

Since commercial operation, the Company has been selling its share of Seabrook Unit 1's output on a short-term basis at prices substantially below its actual operations, maintenance and capital related costs. The level of operating revenues of the Company depends upon the price per kWh of its short-term sales and Unit 1's capacity factor.

Due to minimal outages in 1993, there was a slight increase in operating revenue of 6.9%. Consequently, there was a higher average capacity factor over 12 months in 1993 as compared to 1992; 89.9% vs 77.9%, respectively. The average kWh sales price was 2.24 cents in 1993 as compared to 2.39 cents in 1992.

Scheduled refueling outages of Seabrook Unit 1 in both 1992 and 1991 had a negative impact on the Unit's capacity factor. However, a higher capacity factor averaged over twelve months in 1992 as compared to 1991, 78% vs. 68% respectively, contributed to the 15.5% growth in kWh sales and the $2.1 million, or 10.1%, improvement in revenues despite a 5.2% decline in the average per kWh sales price. The average kWh sales price was 2.39 cents in 1992 as compared to 2.52 cents in 1991.

Expenses

1993 vs 1992

Other Operation & Maintenance expense decreased $4.0 million from 1992 primarily due to (i) operational efficiencies throughout 1993 as compared to 1992 and (ii) fewer repair outages resulting in lower maintenance expenses.

Income & Deferred taxes decreased by $29.3 million due primarily to the reversal of accumulated deferred tax benefits in 1992 relating to net operating losses and alternate minimum tax credit carryforwards which are limited due to the effect of changes in ownership of the Company. Also, the Company began recognizing deferred tax assets relating to net operating losses subsquent to the change in ownership of the Company which occurred on February 5, 1993.

Total Interest changes for 1993 decreased $1.3 million due to the Company's higher debtor-in-possession financing in 1992 and a lower prime rate in 1993.

1992 vs 1991

Fuel Expense represents the Company's amortization of fuel costs associated with Seabrook Unit 1 generation during each respective period. In 1992, Fuel Expense associated with the Company's 12.1% interest in Unit 1 decreased approximately $400,000, or 5.6% as compared to 1991. This decrease is due primarily to a reduction in the average price of fuel offset somewhat by greater generation in 1992.

Other Operation and Maintenance expenses for 1992 compared to 1991 decreased approximately $700,000 due primarily to a shorter refueling outage in 1992 than in 1991.

Reorganization Expenses increased by approximately $630,000 in 1992 as a result of increased activity relating to the Company's bankruptcy proceeding.

Income and Deferred taxes increased by $35.4 million due primarily to the reversal of accumulated deferred tax benefits relating to net operating loss and alternate minimum tax credit carryforwards which are limited due to the effect of changes in the ownership of the Company which will result in the deconsolidation of the Company from the EUA tax group.

Net Interest charges for 1992 decreased by $8.7 million to $1.4 million due primarily to interest expense accrued in 1991 prior to February 28, 1991. Total Interest Expense for 1992 relates to the Company's debtor-in-possession financing. Total Contractual Interest Expense for 1992 was approximately $51.0 million. Of this amount, interest in connection with the debtor-in-possession financing for 1992 was $1.3 million.

Financial Condition and Liquidity

Liquidity:

The cash resources of the Company are primarily dependent upon the price at which it sells its share of electricity generated by Seabrook Unit 1 and the operating capacity of Seabrook Unit 1. At current market prices, the cash generated by such electricity sales is less than the Company's on-going cash requirements. While operating in Chapter 11, the Company intends, with the approval of the Bankruptcy Court, to continue making payments of its on-going obligations under the JOA to the extent its cash flow permits.

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses including, without limitation, operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA could adversely affect its entitlement in Unit 1.

Pursuant to the Settlement Agreement of December 30, 1992, EUA paid $20 million to EUA Power, $14.7 million of which was used to repay the DIP financing (as discussed below). (See Item 1 for bankruptcy proceeding discussion).

The Company has filed consolidated income tax returns together with EUA and other EUA affiliates. As a result of such consolidated filings, certain federal income tax benefits available to the Company have reduced the federal income tax obligations of EUA and such other EUA affiliates. Under a tax allocation agreement between EUA and its subsidiaries, EUA and its subsidiaries compensate each other for the use of the tax benefits.

As a result of the redemption of the Company's outstanding common stock, the Company was deconsolidated from the EUA tax group effective February 5, 1993. Under the terms of the Settlement Agreement, EUA is entitled to utilize the Company's tax credits to reduce EUA's 1993 consolidated tax liability without compensation. The Company will be included in EUA's consolidated tax returns for the years 1992 and 1993.

To the extent that the Company's carryforwards of net operating losses, investment tax credits, alternative minimum tax credits, and deductions attributable to built in losses are available after the Company is no longer part of the consolidated return, the Company expects that these carryforwards will be significantly limited due to the impact of provisions of the tax law relating to the treatment of debt forgiveness in bankruptcy and the effect of changes in the ownership of the Company.

DIP Financing:

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses including, without limitation, operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA could adversely affect its entitlement in Unit 1. At current market prices, the cash generated by such electricity sales continues to be less than the Company's on-going cash requirements.

On August 29, 1991, the Bankruptcy Court approved a Stipulation and Consent Order (the First Stipulation) with respect to DIP Financing to be provided by certain joint owners of Seabrook for the benefit of the Company. The First Stipulation was entered into by the Company and CL&P and UI (the Participating Joint Owners), two of the other eleven joint owners of the Seabrook Project, as well as the Bondholders Committee. The First Stipulation was also approved by the NHPUC and the SEC under the 1935 Act.

On July 21, 1992, the Bankruptcy Court issued a procedural order permitting an extension of the First Stipulation. For the period after September 30, 1992 until March 5, 1993, the procedural order permitted continued debtor-in-possession financing on a month-to-month basis at the sole discretion of the Participating Joint Owners terminable on 30 days notice. The Bankruptcy Court issued a second procedural order on September 8, 1992 increasing to $22 million from $15 million the amount of advances outstanding at any one time permitted under the First Stipulation. The Participating Joint Owners continued to advance funds under the First Stipulation, as amended, until the amounts advanced thereunder were repaid with the proceeds of the Company's Settlement Agreement with EUA. The First Stipulation expired on March 5, 1993.

A second stipulation was entered into by the Company and the Participating Joint Owners and was approved by the Bankruptcy Court and various regulatory authorities. However, that stipulation did not become effective, and on March 5, 1993, the Company and the Participating Joint Owners entered into a third stipulation (the Third Stipulation) which was approved by the Bankruptcy Court.

The Third Stipulation provides that the Participating Joint Owners shall provide up to a maximum of $20 million in advances to the Company to enable the Company to pay its <u>pro rata</u> share of the Seabrook Project's operating expenses, expenses of the Company in connection with its Chapter 11 proceedings and certain other costs of operation of the Company. Pursuant to the Third Stipulation, the advances made by the Participating Joint Owners bear an interest rate equal to the prime rate of The First National Bank of Boston plus 7% per annum. The Third Stipulation provides the Participating Joint Owners with a priority lien on all the Company's assets, which lien has priority over the Bondholders' mortgage. The Third Stipulation further provides that in the event of a default thereunder, the Participating Joint Owners are entitled to purchase the Company's Seabrook Interest for 75% of the lesser of fair market value or book value and to apply all or part of the amounts owing under the Third Stipulation against the purchase price. The Third Stipulation terminates on the earliest to occur of (a) July 1, 1994, (b) the Effective Date or the closing of a sale of all or substantially all of the Company's assets or business, and (c) an event of default under the terms of the Third

Stipulation. The Company is in default of the Third Stipulation for, among other reasons, failure to obtain financing for the Plan by the date required in the Third Stipulation. Although the Company has been in default since November 1, 1993, the Participating Joint Owners have continued to provide financing pursuant to the Third Stipulation. There is, however, no assurance that they will continue to do so. As of March 25, 1994, outstanding advances under the Third Stipulation were approximately $2.2 million in the aggregate.

If the Plan is confirmed by the Bankruptcy Court and the Omega Financing is obtained, the Company will repay amounts owing under the Third Stipulation out of the proceeds of the Omega Financing. The Company cannot predict whether the Plan will be confirmed or the Omega Financing obtained.

The Company cannot predict whether it will be able to enter into contracts for the sale of its share of the Seabrook Project capacity or energy prior to the termination of the Third Stipulation, if at all, at prices sufficient to cover its costs and provide for repayment of advances which may be outstanding under the Third Stipulation, or whether alternative debtor-in-possession financing can be arranged to repay advances.

Company Debt:

The current face amount of principal and accrued interest to February 28, 1991 on the Company's Secured Notes is $279,597,200 and $14,126,174, respectively. The Secured Notes are collateralized by a security interest in the Company's 12.1% ownership interest in the realty and personalty of the Seabrook Project. Early in the Chapter 11 proceeding, the Company raised the issue of whether the Secured Noteholders are also secured by the Company's "entitlement" to electricity from Seabrook Unit 1. In light of the Plan, this issue did not need to be resolved in the Chapter 11 case. As a result of the bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued. All of the Secured Notes will be converted into common stock of the Company on the Effective Date.

The Company also has outstanding 180,000 CICs evidencing the right to receive additional payments contingent upon and measured by the Company's income in certain years following the commercial operation of Seabrook Unit 1. Under the Plan, the CICs will be extinguished on the Effective Date. Such Secured Notes and CICs are solely the obligation of the Company and are not guaranteed by EUA or any other person (see Reorganization Plan above).

Construction:

Cash construction and nuclear fuel expenditures for the year ended December 31, 1993 were approximately $6.9 million.

The Company's cash construction program is estimated to be approximately $4.3 million in 1994 and aggregate approximately $23.4 million for the years 1995 through 1998.

Nuclear Fuel Disposal and Nuclear Plant Decommissioning Costs

The Seabrook Project joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of fuel in accordance with the NWPA. The NWPA requires (subject to various contingencies) that the federal government design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such wastes and fuel. The NWPA specifies that the DOE provide for the disposal of such wastes and spent nuclear fuel starting in 1998. Objections on environmental and other grounds have been asserted against proposals for storage as well as disposal of spent fuel. The DOE anticipates that a permanent disposal site for spent fuel will be ready to accept fuel for storage on or before 2010. However, the NRC, which must license the site, stated only that a permanent repository will become available by the year 2025. At the Seabrook Project there is on-site storage capacity which, with minimal capital expenditures, should be sufficient for twenty years or until the year 2010. No near-term capital expenditures are anticipated to deal with any increase in storage requirements after 2010.

The estimated cost to decommission Seabrook Unit 1, based on a study performed for the lead owner of the Plant is approximately $351 million in 1993 dollars. The Company's share of that amount is approximately $42.6 million, or 12.1%. In 1993, the Company paid approximately $895,000 in decommissioning expenses.

The agreements of purchase and sale under which the Company purchased its Seabrook Interest required the Company to establish a fund of $10 million to secure payment of part of its share of the decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. In May 1990, EUA guaranteed this obligation and the entire fund was released to the Company. Under the Settlement Agreement EUA reaffirmed this guaranty. (See <u>Bankruptcy Proceeding</u> - Settlement Agreement above.)

<u>Changes in Accounting Standards</u>

In February 1992, FASB issued statement No. 109, "Accounting for Income Taxes" (FAS109) which essentially supersedes FASB Statement No. 96 (FAS96) (see Note D of Notes to Financial Statements - Income Taxes). The Company adopted FAS109 in the first quarter of 1993. The Company adopted FAS96 in 1990 and as a result was not significantly impacted by FAS109.

In December 1990, FASB issued Statement No. 106, "Accounting for Post-Retirement Benefits other than Pensions and in November 1992 issued Statement No. 112, "Accounting for Post-Employment Benefits" which were adopted by the Company on January 1, 1993 and January 1, 1994, respectively. Since the Company presently has no employees, the adoption of such statements had no significant impact.

<u>Other</u>

On January 8, 1992, the Massachusetts Municipal Wholesale Electric Cooperative and its member municipalities, all of which are members of NEPOOL, filed a suit in Massachusetts Superior Court against the investor-owned utilities that are also members of NEPOOL. The suit alleges damages by NEPOOL's establishment of minimum size requirements for generating units designated as pool-planned generating units. The suit names as defendants members of NEPOOL, including the Company. Management cannot predict the ultimate outcome of this proceeding at this time. Discovery has not begun, pending resolution of certain procedural matters. The FERC initiated an action ultimate outcome of this proceeding at this time. Discovery has not begun, pending resolution of certain procedural matters. The FERC initiated an action when the EUA subsidiaries and other participants filed an amendment to the NEPOOL Agreement with the FERC that concerns many of the issues raised in the Massachusetts litigation. The plaintiffs in the Massachusetts litigation and one other participant have objected to the amendment, and have sought to prevent or delay its effectiveness. The FERC has not yet determined whether or when it will hold hearings on this matter. Management cannot predict the ultimate outcome of this proceeding at this time.

In June 1991, the State of New Hampshire imposed a Nuclear Station Property Tax applicable only to the Seabrook Project. The Company paid its share of the tax, aggregating $4.2 million through December 31, 1992. In October 1991 the Attorneys General of Connecticut, Massachusetts and Rhode Island petitioned the United States Supreme Court in an original jurisdiction case for a determination of the legality of the tax, and in January 1992 the Supreme Court agreed to take the case. The parties to the litigation and other Joint Owners of Seabrook entered into a Settlement Agreement on April 13, 1993. In general, the terms of the Settlement Agreement are expected to result in a significant reduction in annual state taxes paid by the Company. In addition, under the terms of the Settlement Agreement, certain of the prior payments of the tax by the Company will be permitted to be credited against future taxes due. The Bankruptcy Court has approved the Settlement Agreement with respect to the Company.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The response to this item is submitted in the response found under Item 14(a)(i) in this report.

Item 9. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF REGISTRANT

(a), (b), (c), (d) and (e) The name, age and position of the sole director and executive officer of the Company as of March 21, 1994, are listed below with his business experience during the past five years.

Name, Age and Position	Business Experience During Past 5 Years
John R. Stevens, 52 Director and President	Director since July 1987; President since August 1990; Executive Vice President from October 1987 to July 1990; President of EUA since July 1990; Senior Executive Vice President of EUA from January 1990 to June 1990; Chief Operating Officer of EUA since January 1990; Executive Vice President of EUA from June 1987 to December 1989.

Mr. Stevens is also President, Trustee and Chief Operating Officer of EUA; Vice Chairman and Director of Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and EUA Cogenex Corporation; President and Director of EUA Energy Investment Corporation, EUA Ocean State Corporation, EUA Service Corporation and Montaup Electric Company.

Messrs. Richard M. Burns, Arthur A. Hatch, Clifford J. Hebert, Jr., William F. O'Connor, Donald G. Pardus and John R. Stevens, who have been officers or directors of the Company since its formation in 1986, resigned their positions effective December 30, 1992, with the exception of Mr. Stevens who remains the sole officer and director of the Company. Mr. Stevens serves at the request, and subject to direction of the Bondholders Committee.

The Bondholders Committee has disclosed the names of two individuals proposed to serve on the Board of Directors of the Company (the New Board) after the Effective Date. The proposed two members of the New Board are John A. Tillinghast and Walter H. Goodenough. The Bondholders Committee is also considering other candidates to serve as members of the New Board. The persons who will serve on the New Board will be finally determined before the Effective Date. The New Board will take office upon the Effective Date. The New Board will serve until its members resign or are replaced in accordance with New Hampshire corporate law and the requirements of the Company's charter and by-laws.

Name, Age and Position	Business Experience During Past 5 Years
John A. Tillinghast, 66 Director upon Effective Date	Chairman of the Energy Board of the National Academy of Sciences and President of Tillinghast Technology Interests, a Consultant to the US utility industry.
Walter H. Goodenough, 54 Director upon Effective Date	Consultant to the U.S. utility industry Vice President - Public Affairs, Texas Utilities Services. Vice President - Finance, Texas Utilities Services. Treasurer, Texas Utilities Company.

Mr. Tillinghast has more than 30 years of experience in the utility industry in various functions. In his current employment, Mr. Tillinghast serves as consultant to various corporations relative to cogeneration, alternative energy projects, third party power generation and general restructuring of the US utility industry. Mr. Tillinghast holds a M.S. in Mechanical Engineering from Columbia University.

Mr. Goodenough has more than 30 years of utility experience with the Texas Utilities System. Before joining Texas Utilities Services in 1983, he worked for twenty years at Texas Power & Light Co. where he became Vice President and CFO. Mr. Goodenough has been involved in all executive management aspects of the utility business including direct responsibility in financial management resource planning, investor relations, rates and regulation, governmental affairs and field operations. Currently, he is retired from the Texas Utilities System and serves as a consultant to the U.S. utility industry. Mr. Goodenough is a Certified Public Accountant and holds a B.A. in accounting from Texas A&M University.

(f) Except for the Registrant's Chapter 11 filing, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any director or executive officer during the past five years.

Item 11. EXECUTIVE COMPENSATION

The executive officer of the Company receives no compensation from the Company.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

(a) Security ownership of certain beneficial owners.

Pursuant to the terms of the Settlement Agreement, the Company redeemed all of its outstanding common and preferred stock on February 5, 1993 (See Item 1, Bankruptcy Proceeding).

(b) Security Ownership of Management as of March 21, 1994.

None

(c) Except as described under Bankruptcy Proceeding (See Item 1) the Company knows of no contractual arrangements which may at a subsequent date result in a change in control of the Company.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None

PART IV

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

(a)(1) Financial Statements:

The following financial statements and supplementary data are filed herewith as required by Item 8.

Statements of Loss for the three years in the period ended December 31, 1993.

Statements of Retained (Deficit) Earnings for the three years in the period ended December 31, 1993.

Statements of Cash Flows for the three years in the period ended December 31, 1993.

Balance Sheets at December 31, 1993 and 1992.

Statements of Capitalization at December 31, 1993 and 1992.

Notes to Financial Statements at December 31, 1993, 1992 and 1991.

Report of Independent Accountants dated April 7, 1994.

(a)(2) Financial Statement Schedules:

The following additional financial statement schedules are filed herewith.

1. Financial Statement Schedules:

Schedule V - Property, Plant and Equipment for the three years ended December 31, 1993.

Schedule VI - Accumulated Depreciation, Depletion and Amortization of Property, Plant, and Equipment for the three years ended December 31, 1993.

Schedule IX - Short-term Borrowings for the three years ended December 31, 1993.

Schedule X - Supplementary Income Statement Information for the three years ended December 31, 1993.

All other schedules have been omitted since the required information is not present or not sufficiently material to require submission of the schedule, or because the information required is included in the financial statements or the notes thereto.

(a)(3) Exhibits (*denotes filed herewith)

3-1 Articles of Incorporation of EUA Power Corporation, as amended (Exhibit 3-1, Registration No. 33-10978; Exhibit 3-3, Form 10-K of EUA Power for 1988, File No. 33-10978).

3-2 By-Laws of EUA Power Corporation as amended (Exhibit 3-2, Form 10-K of EUA Power for 1988, File No. 33-10978).

3-3 Articles of Amendment to the Articles of Incorporation of EUA Power Corporation changing corporate name from EUA Power Corporation to Great Bay Power Corporation.

4-1 Indenture of EUA Power Corporation to State Street Bank and Trust Company, Trustee, dated as of November 15, 1986 (Exhibit 4-1 Registration No. 33-10978).

4-2 First Supplemental Indenture dated as of February 24, 1987 of EUA Power Corporation (Exhibit 4-35, Form 10-K of EUA for 1986, File No. 1-5366).

4-3 Second Supplemental Indenture dated as of May 1, 1988 of EUA Power Corporation (Exhibit 4-40, Form 10-K of EUA for 1988, File No. 1-5366).

4-4 Third Supplemental Indenture dated as of November 1, 1988 of EUA Power Corporation (Exhibit 4-41, Form 10-K of EUA for 1988, File No. 1-5366).

4-5 Form of Note Purchase Agreement (Exhibit 1, Certificate of Notification Pursuant to Rule 24, File No. 70-7161).

4-6 Form of Note Exchange Inducement Agreement (Exhibit 4-6, Registration No. 33-23127).

4-7 Form of Registration Rights Agreement relating to Exhibit 4-6 (Exhibit 4-7, Registration No. 33-231270).

10-1 Agreement of Purchase and Sale between Bangor Hydro-Electric Company ("BHCE") and Eastern Utilities Associates ("EUA") dated February 19, 1986 (Exhibit B-6, File No. 70-7161).

10-2 Addendum to Agreement of Purchase and Sale between BHEC and EUA (Exhibit B-6(a), File No. 70-7161).

10-3 Agreement of Purchase and Sale between Central Maine Power Company ("CMPC") and EUA dated February 19, 1986 (Exhibit B-7, File No. 70-7161).

10-4 Addendum to Agreement of Purchase and Sale between CMPC and EUA (Exhibit B-7(a), File No. 70-7161).

10-5 Agreement of Purchase and Sale between Central Vermont Public Service Corporation ("CVPSC") and EUA dated as of February 19, 1986 (Exhibit B-8, File No. 70-7161).

10-6 Addendum to Agreement of Purchase and Sale between CVPSC and EUA (Exhibit B-8(a), File No. 70-7161).

10-7 Agreement of Purchase and Sale between Maine Public Service Company ("MPSC") and EUA dated April 7, 1986 (Exhibit B-9, File No. 70-7161).

10-8 Addendum to Agreement of Purchase and Sale between MPSC and EUA (Exhibit B-9(a), File No. 70-7161).

10-9 Agreement of Purchase and Sale between Fitchburg Gas and Electric Company ("FG&E") and EUA dated April 8, 1986 (Exhibit B-1, File No. 70-7251).

10-10 Addendum to Agreement of Purchase and Sale between FG&E and EUA (Exhibit B-1(a), File No. 70-7251).

10-11 Agreement dated as of May 1, 1973 for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units among Public Service Company of New Hampshire and other utilities including Montaup, as amended as of May 24, 1974, June 21, 1974, September 25, 1974, October 25, 1974, January 31, 1975, as supplemented by Letter Agreement dated April 27, 1978 and amended as of April 18, 1979 (two amendments), April 25, 1979, June 8, 1979, October 11, 1979, December 15, 1979, June 16, 1980, December 31, 1980, June 1, 1982, April 27, 1984, June 15, 1984, March 8, 1985, March 14, 1986, May 1, 1986, March 14, 1986, May 1, 1986. September 1, 1986, November 1987, January 13, 1989 and November, 1990. (Exhibit 13-57, Registration No. 2-48966; Exhibit B-6, Form U5S of EUA for year 1974; Exhibit 5-130, Registration No. 2-62862; Exhibit 5-70, Registration No. 2-65785; Exhibit 2, Form 10-K of EUA for 1979, File No. 1-5366; Exhibit 5-34, Registration No. 2-69052; Exhibit 10-36, Form 10-K of EUA for 1980, File No. 1-5366; Exhibit 10-69, Registration No. 2-80205; Exhibit 2, Form 10-Q of EUA for the Quarter Ended March 31, 1984, File No. 1-5366; Exhibit 3, Form 10-Q of EUA for the Quarter Ended June 30, 1984, File No. 1-5366; Exhibit 10-70, Form 10-K of EUA for 1985, File No. 1-5366; Exhibits 10-80 and 10-81, Form 10-K of EUA for 1986, File No. 1-5366; Exhibits 10-95 and 10-96, Form 10-K of EUA for 1987, File No. 1-5366; Exhibit 10-101, Form 10-K of EUA for 1988, File No. 1-5366; Exhibit 10-110, Form 10-K of EUA for 1990, File No. 1-5366).

10-12 Decommissioning Costs Security Agreement of November 25, 1986 (Exhibit A-7, File No. 70-7161).

10-13 Agreement dated as of October 20, 1986 among BHCE, CMPC, CVPSC, MPSC and EUA Power Corporation relating to the use of certain transmission facilities (Exhibit 10-13, Registration No. 32-10978).

10-14 Settlement Agreement dated November 18, 1992 among EUA Power Corporation, Eastern Utilities Associates and the Official Bondholders' Committee of EUA Power Corporation (Exhibit 10-69, Form 10-K of EUA for 1992, File 1-5366).

*10-15 Power Purchase Agreement between UNITIL Power Corporation and the Company dated May 1, 1993.

*10-16 Power Purchase Option Agreement between UNITIL Power Corporation and the Company dated May 1, 1993.

10-17 Marketing Agent Agreement between UNITIL Corporation and the Company dated April 1, 1993. (Exhibit 10-17, Form 10-K of the Company for 1992, File No. 33-10978)

10-18 Stipulation and Consent Order for 1993-1994 Financing by Participating Joint Owners. (Exhibit 10-18, Form 10-K of the Company for 1992, File No. 33-10978)

10-19 Bondholders' Committee Fifth Amended Plan of Reorganization (Exhibit 10-19, Form 10-K of the Company for 1992, File No. 33-10978)

*10-20 Bondholders' Committee First Modification to Fifth Amended Plan of Reorganization.

*10-21 Second Mortgage granted to UNITIL Power Corporation by the Company dated December 22, 1993.

*10-22 Mortgage granted to UNITIL Power Corporation by the Company dated December 22, 1993.

(b) Reports on Form 8-K.
None.

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.

Signature	Title	Date
GREAT BAY POWER CORPORATION		
By /s/ John R. Stevens John R. Stevens	President and Director (Principal Executive, Financial and Accounting Officer)	April 7, 1994

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GREAT BAY POWER CORPORATION

Item 8 and Item 14(a)(1)
Financial Statements and
Supplementary Data

Item 14(a)(2)
Financial Statement Schedules

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)
STATEMENTS OF LOSS
December 31,
(Debtor-in-Possession)(In Thousands)

	1993	1992	1991
Operating Revenues	$ 24,620	$ 23,027	$ 20,919
Operating Expenses:			
Fuel	6,869	6,735	7,133
Other Operation	13,052	15,411	15,494
Maintenance	3,070	4,677	5,269
Reorganization Expenses	1,867	1,699	1,069
Depreciation and Amortization	9,020	8,816	8,737
Taxes Other Than Income (Schedule X)	3,878	6,077	3,948
Income Tax (Credit)	(630)	(17,497)	(3,444)
Deferred Taxes (Credit)	(3,421)	42,245	(7,237)
Total Operating Expenses	33,705	68,163	30,969
Operating (Loss)	(9,085)	(45,136)	(10,050)
Deferred Income Taxes	(459)	(919)	
Other Income - Net	226	(47)	287
Income Before Interest Charges	(9,318)	(46,102)	(9,763)
Interest Charges:			
Interest on Long-Term Debt (Contractual Interest Expense for 1993 and 1992 was $48,929,510, respectively, and for 1991 was $50,071,437)			8,204
Other Interest Expense (Contractual Interest Expense for 1993, 1992 and 1991 was $114,763, $2,099,954, and $2,744,427, respectively)	115	1,366	1,825
Net Interest Charges	115	1,366	10,029
Net Loss	$ (9,433)	$ (47,468)	$ (19,792)

STATEMENTS OF RETAINED (DEFICIT) EARNINGS
Years Ended December 31,
(Debtor-in-Possession)(In Thousands)

	1993	1992	1991
Retained (Deficit) Earnings - Beginning of Year :	$ (130,360)	$ (82,892)	$ (63,100)
Net Loss	(9,433)	(47,468)	(19,792)
Retained (Deficit) Earnings - End of Year	$ (139,793)	$ (130,360)	$ (82,892)

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

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)
STATEMENTS OF CASH FLOWS
December 31,
(Debtor–in–Possession)(In Thousands)

	1993	1992	1991
CASH FLOW FROM OPERATING ACTIVITIES:			
Net Loss	$ (9,433)	$ (47,468)	$ (19,792)
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	8,124	8,002	8,472
Amortization of Nuclear Fuel	5,818	5,853	6,453
Deferred Taxes	(2,962)	37,155	(7,114)
Investment Tax Credit, Net	(630)	(268)	(269)
Other – Net	1,026	(2,169)	(1,855)
Net Changes of Working Capital:			
Accounts Receivable	(97)	3,793	145
Accounts Payable	(122)	(910)	1,030
Accrued Taxes	139	(12,017)	2,583
Other – Net	(1,401)	4,245	5,382
Net Cash (Used In) Provided from Operating Activities	462	(3,784)	(4,965)
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction Expenditures	(6,885)	(2,464)	(4,614)
Net Cash (Used In) Provided From Investing Activities	(6,885)	(2,464)	(4,614)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuances:			
Financing Expenses			(542)
Debtor–in–Possession Financing	1,744	(9,068)	9,068
Settlement Proceeds		20,000	
Net Increase in Short–Term Debt			1,170
Net Cash Provided from Financing Activities	1,744	10,932	9,696
Net Increase (Decrease) in Cash	(4,679)	4,684	117
Cash and Temporary Cash Investments at Beginning of Year	4,817	133	16
Cash and Temporary Cash Investments at End of Period	$ 138	$ 4,817	$ 133
Cash paid during the year for:			
Interest	$	$ 1,619	$ 316
Income Taxes (Benefits)	$	$	$ (2,200)

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

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)
BALANCE SHEETS
December 31,
(Debtor-in-Possession)(In Thousands)

ASSETS

		1993		1992
Utility Plant and Other Investments:				
Utility Plant and Nuclear Fuel (Schedule V)	$	542,180	$	536,620
Less:				
Accumulated Provision for Depreciation (Schedule VI) and Amortization		56,556		38,145
Provision for Estimated Loss on Seabrook Investment		51,459		52,903
Deferred Allowance for Funds Used During Construction		122,233		126,583
Total Net Utility Plant		311,932		318,989
Current Assets:				
Cash and Temporary Cash Investments		138		4,817
Accounts Receivable:				
Customers		2,470		2,373
Prepaid Seabrook Funding		4,044		2,342
Other Current Assets		43		168
Total Current Assets		6,695		9,700
Deferred Debits:				
Unamortized Debt Expense		5,069		5,069
Other Deferred Debits		894		
Total Deferred Debits		5,963		5,069
Total Assets	$	324,590	$	333,758

CAPITALIZATION AND LIABILITIES

		1993		1992
Capitalization:				
Common Equity	$	(139,783)	$	(130,350)
Redeemable Preferred Stock		63,090		63,090
Total Capitalization		(76,693)		(67,260)
Liabilities Subject to Compromise :				
Long-Term Debt due within One Year		279,597		279,597
Accounts Payable		141		141
Interest Accrued		14,126		14,126
Total Liabilities Subject to Compromise		293,864		293,864
Liabilities Not Subject to Compromise :				
Accounts Payable		91		213
Taxes Accrued		581		442
Debtor-in-Possession Financing		1,744		
Unamortized Investment Tax Credits		6,778		7,412
Accumulated Deferred Taxes		51,484		54,444
Other Liabilities and Deferred Credits		46,741		44,643
Total Liabilties Not Subject to Compromise		107,419		107,154
Commitments and Contingencies (B,G)				
Total Liabilities and Capitalization	$	324,590	$	333,758

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

GREAT BAY POWER CORPORATION
(f.k.a. EUA Power Corporation)
STATEMENTS OF CAPITALIZATION
December 31,
(Debtor-in-Possession)(In Thousands)

	1993	1992
Common Equity		
Common Stock and related Additional Paid-In Capital, $.01 par value, authorized, issued and outstanding 10,000 shares	$ 10	$ 10
Less: Treasury Stock, 10,000 Shares	(10)	(10)
Paid-In Capital-Treasury Stock	10	10
Retained earnings	(139,793)	(130,360)
Total Common Equity	(139,783)	(130,350)
Redeemable Preferred Stock		
Class A 25% Cumulative Convertible Preferred Stock, $100 par value authorized 750,000 shares, issued and outstanding 630,900 shares	63,090	63,090
Less: Treasury Preferred Stock, 630,900 Shares	(63,090)	(63,090)
Paid-In Capital-Treasury Stock	63,090	63,090
Total Preferred Stock	63,090	63,090
Long-term Debt Subject to Compromise		
17-1/2% Series B Secured Notes due 1993	180,000	180,000
17-1/2% Series C Secured Notes due 1992	99,597	99,597
Total	279,597	279,597
Less Portion due within One Year	279,597	279,597
Total Long-Term Debt	0	0
Total Capitalization	$ (76,693)	$ (67,260)

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

GREAT BAY POWER CORPORATION
NOTES TO FINANCIAL STATEMENTS
December 31, 1993, 1992 and 1991

Note A - Business:

The Registrant, Great Bay Power Corporation (formerly known as EUA Power Corporation), is a New Hampshire corporation, incorporated in 1986, authorized by the NHPUC to engage in business as a public utility for the purposes of participating as a joint owner in the Seabrook Project, acquiring its 12.1% interest in the Seabrook Project and selling its share of the output of Seabrook Unit 1 for resale. The Company, organized as wholly-owned subsidiary of EUA, became fully independent of EUA on February 5, 1993 in connection with the bankruptcy proceeding described in Note B -- Bankruptcy Proceeding. The Company became a wholesale generating company when Seabrook Unit 1 commenced commercial operation on August 19, 1990.

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the Bankruptcy Code. The Bankruptcy Court confirmed the Bondholders Committees' Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega Advisers, Inc. ("Omega") or its designees to provide $35 million of equity financing for the Company (the "Omega Financing"). The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Fifth Amended Plan of Reorganization, as modified by the First Modification is hereinafter referred to as the "Plan." The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. the Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. (See

Bankruptcy Proceeding below for a discussion of the Company's bankruptcy proceeding and the Omega Financing.)

Seabrook Unit 1 is a 1,150 MW nuclear generating plant located in Seabrook, New Hampshire. The Company acquired its joint ownership interest in the Seabrook Project for approximately $174,000,000 in November 1986 from five New England electric utilities in independently negotiated transactions. At that time, construction of Seabrook Unit 1 was substantially completed. Because Seabrook Unit 2 had been cancelled, the Company assigned no value to it. On March 29, 1991, the Company announced that it had provided an impairment reserve in 1990 against its investment in Seabrook Unit 1. At December 31, 1993, the Company's net investment in Seabrook Unit 1, including nuclear fuel, was approximately $312 million.

The Company has no employees. John R. Stevens, president of EUA serves as president and sole director of the Company at the request and subject to the direction of the Bondholders Committee. Mr. Stevens expects to resign both positions on the Effective Date. Since the Company's organization, EUA Service, a wholly owned subsidiary of EUA, has provided, or arranged for, various management and professional services. Pursuant to various Bankruptcy Court orders, EUA Service continues to provide similar services to the Company. Under the terms of the Settlement Agreement (as discussed below), EUA Service will continue to provide, at cost, certain services to the Company at the request of the Bondholders Committee for a period of not more than two years from the effective date of the Settlement Agreement. However, such services specifically exclude the marketing of the Company's entitlement in Seabrook Unit 1 on a long-term basis. The Company has agreed with UNITIL that an affiliate of UNITIL will replace EUA Service in providing various services on the Effective Date. In addition, the Company has entered into a contract with an affiliate of UNITIL pursuant to which that affiliate is marketing the Company's share of electricity from Seabrook Unit 1.

Note B - Bankruptcy Proceeding:

Background:

On February 28, 1991, the Company filed a voluntary petition in the Bankruptcy Court for the District of New Hampshire for protection under Chapter 11 of the federal Bankruptcy Code and has been conducting its business as a Debtor and Debtor-in-Possession under the provisions of the Bankruptcy Code. The Company filed such petition because the cash generated by short-term sales of electricity from its entitlement in Seabrook Unit 1 would have been insufficient to pay interest on its outstanding Secured Notes when interest became due on May 15, 1991 and the prospects for signing long-term power sales contracts prior to that date were minimal. The Company continues its efforts to market its entitlement to Seabrook Unit 1 under the direction of the Bondholders Committee.

Settlement Agreement:

On November 18, 1992, the Company, the Bondholders Committee and EUA entered into a Settlement Agreement which resolved certain adversary proceedings against EUA, brought, or threatened to be brought, by the Bondholders Committee including, (i) a claim for recovery of certain alleged preferential transfers in the aggregate amount of $38.5 million, plus interest;

(ii) a threatened claim for the recovery of $100 million plus treble damages arising from, among other things, certain alleged breaches of fiduciary duties by EUA, EUA Service and the officers and directors of the Company; and, (iii) certain matters arising out of tax sharing agreements between EUA, its subsidiaries, and the Company. The Settlement Agreement also provided for the payment of $20 million to the Company by EUA. The Settlement Agreement further provided for the relinquishment by EUA of its equity interest in the Company and all claims filed in Bankruptcy Court by EUA and its affiliates against the Company. These claims related primarily to obligations of the Company guaranteed and paid by EUA, including $21 million of Solid Waste Disposal Facility Revenue Bonds, issued by the New Hampshire Industrial Development Authority on behalf of the Company and other notes payable. The settlement of these claims was recorded as a deferred credit on the Company's 1992 Balance Sheet, pending the ultimate outcome of the Bankruptcy Proceeding. The Settlement Agreement became effective on December 30, 1992 at which time EUA paid $20 million to the Company. The Company used a substantial portion of the proceeds from the Settlement Agreement to repay amounts outstanding under the First Stipulation (as described below) and to pay reorganization expenses and other operating expenses. The Company redeemed all of its outstanding equity securities which were held by EUA, at no cost, on February 5, 1993. The redeemed shares have been classified as treasury stock on the Company's financial statements as of December 31, 1993 and 1992. As a result of the redemption, the Company is no longer part of the EUA System.

Under the Settlement Agreement, EUA reaffirmed its guarantee of up to $10 million of the Company's share of future decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. EUA had guaranteed this obligation in 1990 in order to secure the release to the Company of a $10 million fund established by the Company for the same purpose at the time the Company acquired its Seabrook Interest. Further, under the Settlement Agreement, all of the officers and directors of the Company (except Mr. Stevens) resigned and the Company changed its name to Great Bay Power Corporation. EUA now has no ownership interest in the Company.

Reorganization Plan:

The Bankruptcy Court confirmed the Bondholders Committees Fifth Amended Plan of Reorganization on March 5, 1993. After confirmation, the Company was unable to obtain the $45 million of debt financing contemplated by the Fifth Amended Plan of Reorganization. In February 1994, however, the Bondholders Committee obtained a commitment from Omega or its designees to provide $35 million of equity financing for the Company. The Bondholders Committee prepared a First Modification to Fifth Amended Plan of Reorganization to reflect this change in financing and submitted a Supplemental Disclosure Statement describing that First Modification to the Bankruptcy Court for its approval. The Bankruptcy Court approved the Supplemental Disclosure Statement at a hearing on March 11, 1994. The Plan is scheduled to be mailed to the Company's creditors for their approval on or before April 7, 1994. If the Creditors approve the Plan, the Company expects the Bankruptcy Court to confirm the Plan in a hearing currently scheduled for May 13, 1994, although such confirmation cannot be assured. The Omega Financing and the Plan are subject to approval by certain regulatory authorities. On February 15, 1994 the Nuclear Regulatory Commission issued an order approving a transfer of control of the Company as contemplated by the Omega Financing and extending the deadline for completion of such transfer to June 30, 1994. There can be no assurance that other such approvals will be obtained. Moreover, the Omega Financing is not yet reduced to a definitive agreement. The Plan will not be circulated to creditors unless and until such a definitive agreement has been signed.

The Omega Financing provides for the Company to sell its common stock representing a 60% ownership interest in the Company to Omega or its designees for an aggregate purchase price of $35 million. The 40% balance of the Company's common stock will be issued 34% to the Company's Bondholders in full payment and satisfaction of their secured claims pursuant to the Bonds and 6% to the Company's unsecured creditors with claims in excess of $25,000 in full payment and satisfaction of their claims. These unsecured claims consist primarily of the unsecured deficiency claims of the Bondholders under the Bonds. The holders of unsecured claims of less than $25,000, other than those unsecured claims resulting from the ownership of the Secured Notes, will be paid 50% of the amounts of their claims allowed by the Bankruptcy Court in cash on the Effective Date. The Plan requires that prior to the Effective Date the Bondholders Committee obtain the Omega Financing.

Although a bar date for all claims has been entered and passed, claims arising from the rejection of contracts or claims which the Bankruptcy Court permits to be filed notwithstanding the bar date may dilute the percentage of the unsecured claims held by the Secured Bondholders. All of the previously issued and outstanding equity securities of the Company have been redeemed by the Company. The CICs issued in connection with the Series B Notes or otherwise will be extinguished on the Effective Date. After the Effective Date, the equity of the Company will be represented by a single class of common stock. The Company will use good faith efforts to list its shares of common stock so that they will be tradeable on the American Stock Exchange or the NASDAQ National Market System.

The Bondholders Committee has appointed or will appoint agents to manage the Company's business and to market the Company's share of Seabrook electricity. During the period between the Confirmation of the Plan and the Effective Date, those agents are to report to the Bondholders Committee and, to the extent actions are to be taken outside of the ordinary course of business, such actions shall be subject to the approval of the Bankruptcy Court and regulatory bodies with jurisdiction under applicable law. John R. Stevens, president of EUA, expects to resign as president and director of the Company on the Effective Date. The Bondholders Committee has disclosed the names of two individuals proposed to serve on the Board of Directors (the New Board) of the Company after the Effective Date. The proposed two members of the New Board are John A. Tillinghast and Walter H. Goodenough. The Bondholders Committee is also considering other candidates to serve as members of the New Board. The persons who will serve on the New Board will be finally determined before the Effective Date. The New Board will take office upon the Effective Date. The New Board will serve until its members resign or are replaced in accordance with New Hampshire corporate law and the requirements of the Company's charter and by-laws.

The effectiveness of the Plan is conditioned upon obtaining plan of reorganization financing and approvals from various regulatory agencies including the NRC. The Company has obtained the approval of the NRC, provided the Company obtains plan of reorganization financing. The Company cannot predict whether it will be able to obtain plan of reorganization financing or whether the plan, or any other plan if filled, will be approved by the various regulatory agencies having jurisdiction.

DIP Financing:

The Company is required under the JOA to pay its share of Seabrook Unit 1 and Seabrook Unit 2 expenses including, without limitation, operations and maintenance expenses, construction and nuclear fuel expenditures and decommissioning costs, regardless of Seabrook Unit 1's operations. Under certain circumstances, a failure by the Company to make its monthly payments under the JOA could adversely affect its entitlement in Unit 1. At current market prices, the cash generated by such electricity sales continues to be less than the Company's on-going cash requirements.

On August 29, 1991, the Bankruptcy Court approved a Stipulation and Consent Order (the First Stipulation) with respect to DIP Financing to be provided by certain joint owners of Seabrook for the benefit of the Company. The First Stipulation was entered into by the Company and CL&P and UI (the Participating Joint Owners), two of the other eleven joint owners of the Seabrook Project, as well as the Bondholders Committee. The First Stipulation was also approved by the NHPUC and the SEC under the 1935 Act.

On July 21, 1992, the Bankruptcy Court issued a procedural order permitting an extension of the First Stipulation. For the period after September 30, 1992 until March 5, 1993, the procedural order permitted continued debtor-in-possession financing on a month-to-month basis at the sole discretion of the Participating Joint Owners terminable on 30 days notice. The Bankruptcy Court issued a second procedural order on September 8, 1992 increasing to $22 million from $15 million the amount of advances outstanding at any one time permitted under the First Stipulation. The Participating Joint Owners continued to advance funds under the First Stipulation, as amended, until the amounts advanced thereunder were repaid with the proceeds of the Company's Settlement Agreement with EUA. The First Stipulation expired on March 5, 1993.

A second stipulation was entered into by the Company and the Participating Joint Owners and was approved by the Bankruptcy Court and various regulatory authorities. However, that stipulation did not become effective, and on March 5, 1993, the Company and the Participating Joint Owners entered into a third stipulation (the Third Stipulation) which was approved by the Bankruptcy Court.

The Third Stipulation provides that the Participating Joint Owners shall provide up to a maximum of $20 million in advances to the Company to enable the Company to pay its pro rata share of the Seabrook Project's operating expenses, expenses of the Company in connection with its Chapter 11 proceedings and certain other costs of operation of the Company. Pursuant to the Third Stipulation, the advances made by the Participating Joint Owners bear an interest rate equal to the prime rate of The First National Bank of Boston plus 7% per annum. The Third Stipulation provides the Participating Joint Owners with a priority lien on all the Company's assets, which lien has priority over the Bondholders' mortgage. The Third Stipulation further provides that in the event of a default thereunder, the Participating Joint Owners are entitled to purchase the Company's Seabrook Interest for 75% of the lesser of fair market value or book value and to apply all or part of the amounts owing under the Third Stipulation against the purchase price. The Third Stipulation terminates on the earliest to occur of (a) July 1, 1994, (b) the Effective Date or the closing of a sale of all or substantially all of the Company's assets or business, and (c) an event of default under the terms of the Third Stipulation. The Company is in default of the Third Stipulation for, among other reasons, failure to obtain financing for the Plan by the date required in the Third Stipulation. Although the Company has been in default since November 1, 1993, the Participating Joint Owners have continued to provide financing pursuant to the Third Stipulation. There is, however, no assurance that they will continue to do so. As of March 25, 1994, outstanding advances under the Third Stipulation were approximately $2.2 million in the aggregate.

If the Plan is confirmed by the Bankruptcy Court and the Omega Financing is obtained, the Company will repay amounts owing under the Third Stipulation out of the proceeds of the Omega Financing. The Company cannot predict whether the Plan will be confirmed or the Omega Financing obtained.

Other Matters:

The Company's reorganization expenses are subject to approval by the Bankruptcy Court. For the period March 1, 1991 through August 31, 1993, professionals have submitted fees and expenses in the amount of approximately $5.9 million to the Bankruptcy Court for its approval, and the Bankruptcy Court has provisionally authorized, subject to its review at the conclusion of the Chapter 11 proceeding, payments of approximately $4.5 million. The Company has paid amounts provisionally authorized by the Bankruptcy Court, and those are reflected on the Company's Statement of Loss during the period in which they have been paid.

Since August 31, 1993, no hearings on approval of reorganization expenses have been held and no requests for allowance for such expenses have been made. According to the Supplemental Disclosure Statement, the Bondholders Committee has budgeted reorganization expenses payable on closing of the Omega Financing and subject to Bankruptcy Court approval of $4.5 million.

Under Chapter 11, certain claims against the Company in existence prior to the filing of the petition for relief under the Bankruptcy Code are stayed while the Company continues business operations as debtor-in-possession. These claims are reflected in the Company's Balance Sheet as of December 31, 1993 and December 31, 1992 as "Liabilities Subject to Compromise." Additional claims (Liabilities Subject to Compromise) may arise subsequent to the filing date resulting from rejection of executory contracts and from the determination by the Bankruptcy Court (or agreed to by parties in interest) of allowed contingent and disputed claims. Enforcement of claims secured by certain of the Company's assets (secured claims) also are stayed, although the holders of such claims have the right to move the court for relief from the stay. Secured claims, principally the Secured Notes, are secured by an interest in certain Seabrook Project assets of the Company, principally realty and personalty.

Note C - Summary of Significant Accounting Policies:

System of Accounts: The accounting policies and practices of the Company are subject to regulation by FERC with respect to its rates and accounting. The accounts of the Company are maintained in accordance with the uniform system of accounts prescribed by FERC.

<u>Utility Plant and Depreciation</u>: Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and material, allocated overhead, allowance for funds used during construction and indirect charges for engineering and supervision. For financial statement purposes, depreciation is computed on the straight-line method based on the estimated useful life of Seabrook Unit 1. Since the commencement of commercial operation, the provision for depreciation for the Company has been calculated at 2.5%.

<u>Operating Revenues:</u> Revenues are based on billing rates authorized by FERC and are recognized when billed.

<u>Income Taxes</u>: The general policy of the Company with respect to accounting for federal income taxes is to reflect in income the estimated amount of taxes currently payable and to provide for deferred taxes on certain items subject to temporary differences to the extent permitted by the various regulatory commissions. It is the policy of the Company to defer the investment tax credits and to amortize these credits over the productive lives of the related assets.

<u>Transactions with Affiliates</u>: Prior to February 5, 1993, the Company was a wholly-owned subsidiary of EUA. EUA has interests in other retail and wholesale utility companies, a service corporation, and other non-utility companies.

Transactions between the Company and EUA affiliated companies include the following: accounting, engineering and other services rendered by EUA Service of approximately $209,000, $420,000 and $647,000, in 1993, 1992 and 1991 respectively. Transactions with other affiliated companies are subject to review by applicable regulatory commissions (See Note D - Income Taxes).

<u>Cash and Temporary Cash Investments</u>: The Company considers all highly liquid investments with a maturity of three months or less when acquired to be cash equivalents.

Note D - Income Taxes:

Components of income tax expense for the years 1993, 1992, and 1991 are as follows:

(In Thousands)	1993	1992	1991
Federal:			
Current	$	$ (22,453)	$ (3,175)
Deferred	(3,421)	42,246	(7,237)
Investment Tax Credit, Net	(630)	4,955	(269)
Total Charge to Operations	(4,051)	24,748	(10,681)
Charged to Other Income:			
Current			25
Deferred	459	919	123
Total Charged to Other Income	459	919	148
Total	$ (3,592)	$ 25,667	$ (10,533)

Total income tax expense (credit) was different from the amounts computed by applying federal income tax at statutory rates to book income subject to tax for the following reasons:

(In Thousands)	1993	1992	1991
Federal Income Tax (FIT) Computed at Statutory Rates	(4,559)	$ (7,412)	$ (10,311)
Increases (Decreases) in Tax from:			
Depreciation of Equity AFUDC	548	819	260
Amortization of ITC	(630)	(269)	(269)
FIT Net Operating Loss Carryforward	926		
Reversal of carryforwards due to uncertainties of realization after reorganization		32,527	
Nuclear Decommissioning Costs	313	277	269
Other	(190)	(275)	(482)
Total Income Tax Expense (Credit)	$ (3,592)	$ 25,667	$ (10,533)

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

(In Thousands)	1993	1992	1991
Debt Component of AFUDC	$ (1,458)	$ (1,829)	$ (1,815)
Capitalized Overheads	(59)	(505)	184
Excess Tax Depreciation	7,181	8,069	9,817
Deferred Charges			
Net Operating Loss Carryforward	(8,724)	26,907	(14,911)
Provision for Estimated Loss on Seabrook Investment	459	919	
Alternative Minimum Tax		9,985	
Other	(361)	(382)	(389)
Total	$ (2,962)	$ 43,164	$ (7,114)

The Company adopted FAS96 in 1990 which requires the use of the liability method to record deferred income taxes for temporary differences that are reported in different years for financial reporting and tax purposes. Under the liability method adopted by FAS96, deferred tax liabilities or assets are computed using the tax rates that will be in effect when the temporary differences reverse. Generally, for regulated companies, the changes in tax rates applied to accumulated deferred income taxes may not be immediately recognized in operating results because of ratemaking treatment and provisions in the Tax Reform Act of 1986.

In February 1992, FASB issued Statement No. 109, "Accounting for Income Taxes," which essentially supersedes FAS96. As a result of the adoption of FAS96 in 1990, FAS109, adopted in the first quarter of 1993, had no significant impact. At December 31, 1993 total deferred tax assets for which no valuation allowance was deemed necessary were $26.1 million and total deferred tax liabilities were $77.6 million. Total deferred tax assets and liabilities are comprised as follows:

	Deferred Tax Assets (000)		Deferred Tax Liabilities (000)
Plant Related Differences	$ 16,999	Plant Related Differences	$ 77,444
Other	9,073	Other	112
Total	$ 26,072	Total	$ 77,556

The Company has filed consolidated income tax returns together with EUA and other EUA affiliates. As a result of such consolidated filings, certain federal income tax benefits available to the Company have reduced the federal income tax obligations of EUA and such other EUA affiliates. Under a tax allocation agreement between EUA and its subsidiaries, EUA and its subsidiaries compensate each other for the use of the tax benefits.

As a result of the redemption of the Company's outstanding common stock, the Company was deconsolidated from the EUA tax group effective February 5, 1993. Under the terms of the Settlement Agreement, EUA is entitled to utilize the Company's tax credits to reduce EUA's 1993 consolidated tax liability without compensation (see Note B - Bankruptcy Proceeding). The Company will be included in EUA's consolidated tax return for the years 1992 and 1993.

To the extent that the Company's carryforwards of net operating losses, investment tax credits, alternative minimum tax credits, and deductions attributable to built in losses are available after the Company is no longer part of the consolidated return, the Company expects that these carryforwards will be significantly limited due to the impact of provisions of the tax law relating to the treatment of debt forgiveness in bankruptcy and the effect of changes in the ownership of the Company. As a result, the Company reversed accumulated tax benefits relating to carryforwards of net operating losses and alternative minimum tax credits. The Company has $8.7 million of net operating loss deduction carryforwards which expire in 2008.

Note E - Capital Stock:

Common Stock: On December 31, 1993, the Company had issued and outstanding, no shares of its Common Stock, par value $.01.

Preferred Stock: At December 31, 1993, the Company had outstanding no shares of preferred stock.

Pursuant to the terms of the Settlement Agreements, on February 5, 1993 the Company redeemed all of its outstanding common and preferred stock, which were held by EUA, at no cost to the Company (See Note B - Bankruptcy Proceeding). The redemption has been classified as treasury stock on the Company's financial statements as of December 31, 1993 and 1992.

Note F - Long-Term Debt:

As a result of the Bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued. The current face amount of principal, and accrued interest to February 28, 1991, on the Company's Secured Notes is $279,597,200 and $14,126,174 respectively. The Secured Notes are collateralized in part principally with a security interest in the Company's 12.1% ownership interest in the realty and personalty of the Seabrook Project. As a result of the bankruptcy filing, the Company is in default under the indenture pursuant to which the Secured Notes were issued and ceased accruing interest expense as of February 28, 1991.

The contractual interest expense on the Secured Notes in both 1993 and 1992 was approximately $49 million and in 1991 was approximately $50 million. In 1993, 1992 and 1991, no interest was paid. The Company also had outstanding 180,000 CICs evidencing the right to receive additional payments contingent upon and measured by the Company's income in certain years following the commercial operation of Seabrook Unit 1. Under the Plan, the CICs have been extinguished. (See Note B - Bankruptcy Proceeding)

The Secured Notes and CICs are solely the obligation of the Company and are not guaranteed by EUA or any other person.

The Series B Secured Notes, which have a stated maturity date of May 15, 1993, are redeemable at 100.125% of principal amount. The Series C Secured Notes have a stated maturity date of November 15, 1992.

Note G - Fair Value of Financial Instruments:

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

Cash and Temporary Cash Investments:

The carrying amount approximates fair value because of the short-term maturity of those instruments.

Long-Term Debt:

The fair value of the Company's long-term debt can not be determined at this time. See Note B - Bankruptcy Proceeding for a discussion of the Company's Bankruptcy Proceeding and Reorganization Plan.

Note H - Commitments and Contingencies:

Nuclear Power Issues

Like other nuclear generating facilities, the Seabrook Project is subject to extensive regulation by the NRC. The NRC is empowered to authorize the siting, construction and operation of nuclear reactors after consideration of public health, safety, environmental and anti-trust matters.

The NRC has promulgated numerous requirements affecting safety systems, fire protection, emergency response planning and notification systems, and other aspects of nuclear plant construction, equipment and operation. The Company has been, and may be, affected to the extent of its proportionate share by the cost of any such modifications to Seabrook Unit 1.

Nuclear units in the United States have been subject to widespread criticism and opposition. Some nuclear projects have been cancelled following substantial construction delays and cost overruns as the result of licensing problems, unanticipated construction defects and other difficulties. Various groups have by litigation, legislation and participation in administrative proceedings sought to prohibit the completion and operation of nuclear units and the disposal of nuclear waste. In the event of shutdown of any unit, NRC regulations require that it be completely decontaminated of any residual radioactivity. The cost of such decommissioning, depending on the circumstances, could substantially exceed the owners' investment at the time of cancellation.

Public controversy concerning nuclear power could adversely affect the operating license of Seabrook Unit 1. While the Company cannot predict the ultimate effect of such controversy, it is possible that it could result in a premature shutdown of the unit.

The Price-Anderson Act provides, among other things, that the liability for damages resulting from a nuclear incident would not exceed an amount which at present is about $9.2 billion. Under the Price-Anderson Act, prior to operation of a nuclear reactor, the licensee is required to insure against this liability by purchasing the maximum amount of insurance available from private sources (currently $200 million) and to maintain the insurance available under a mandatory industry-wide retrospective rating program. Should an individual licensee's liability for an incident exceed $200 million, the difference between such liability and the overall maximum liability, currently about $9.2 billion, will be made up by the retrospective rating program. Under such a program, each owner of an operating nuclear facility may be assessed a retrospective premium of up to a limit of $79.3 million (which shall be adjusted for inflation at least every five years) for each reactor owned in the event of any one nuclear incident occurring at any reactor in the United States, with provision for payment of such assessment to be made over time as necessary to limit the payment in any one year to no more than $10 million per reactor owned. The Company would be obligated to pay its proportionate share of any such assessment.

Joint owners of nuclear projects are also subject to the risk that one of their number may be unable or unwilling to finance its share of the project's costs, thus jeopardizing continuation of the project. On May 6, 1991, New Hampshire Electric Cooperative, Inc., a 2.2% owner of the Seabrook Project, announced that it had filed for Chapter 11 bankruptcy protection. A reorganization plan, filed by the New Hampshire Electric Cooperative with the Bankruptcy Court in September, 1991 and revised in January, 1992 was approved by the Bankruptcy Court in March 1992 and approved by the NHPUC on October 5, 1992. All appeals of the NHPUC order approving the reorganization have been resolved in NHEC's favor and the effective date of the plan occurred on December 1, 1993.

Nuclear Fuel and Nuclear Plant Decommissioning:

The Seabrook Project joint owners have made, or expect to make, various arrangements for the acquisition of uranium concentrate, the conversion, enrichment, fabrication and utilization of nuclear fuel and the disposition of that fuel after use. The owners and lead participants of United States nuclear units have entered into contracts with the DOE for disposal of spent nuclear fuel in accordance with the NWPA. The NWPA requires (subject to various contingencies) that the federal government design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel and establish prescribed fees for the disposal of such wastes and fuel. The NWPA specifies that the DOE provide for the disposal of such wastes and spent nuclear fuel starting in 1998. Objections on environmental and other grounds have been asserted against proposals for storage as well as disposal of spent fuel. The DOE anticipates that a permanent disposal site for spent fuel will be ready to accept fuel for storage on or before 2010. However, the NRC, which must license the site, stated only that a permanent repository will become available by the year 2025. At the Seabrook Project there is on-site storage capacity which, with minimal capital expenditures, should be sufficient for twenty years or until the year 2010. No near-term capital expenditures are anticipated to deal with any increase in storage requirements after 2010.

The estimated cost to decommission Seabrook Unit 1, based on a study by the New Hampshire Yankee Division of the Public Service Company of New Hampshire, is approximately $351 million in 1993 dollars: The Company's share of that amount is approximately $42.5 million, or 12.1%. In 1993, the Company paid approximately $895,000 in decommissioning expenses.

The agreements of purchase and sale under which the Company purchased its Seabrook interest required the Company to establish a fund of $10 million to secure payment of part of its share of decommissioning costs of Seabrook Unit 1 and any costs of cancellation of Seabrook Unit 1 or Unit 2. In May 1990, EUA guaranteed this obligation and the entire fund was released to EUA Power. Under the Settlement Agreement, EUA reaffirmed this guaranty.

Seabrook Unit 2:

The Company also has a 12.1% ownership interest in Seabrook Unit 2 in which it has assigned no value. On November 6, 1986, the joint owners of the Seabrook Project, recognizing that Seabrook Unit 2 had been cancelled, voted to dispose of the Unit. Certain assets of Seabrook Unit 2 have been and are being sold from time to time to third parties. Plans regarding disposition of Seabrook Unit 2 are now under consideration, but have not been finalized and approved. The Company is unable, therefore, to estimate the costs for which it would be responsible in connection with the disposition of Seabrook Unit 2. Monthly charges are required to be paid by the Company with respect to Seabrook Unit 2 in order to preserve and protect its components and various warranties.

Construction Expenditures

Great Bay Power's cash construction expenditures, including nuclear fuel, are estimated to be approximately $4.3 million in 1994 and aggregate approximately $23.4 million for the years 1995 through 1998.

SEC Review

In January of 1991, the SEC's Division of Corporation Finance commenced a review of the Company's Annual Report on Form 10-K for the year ended December 31, 1989 and subsequent Quarterly Reports on Form 10-Q. The Company submitted written responses to all of the inquiries made by the Division of Corporate Finance. In May of 1991, the Company was informed by the SEC's Division of Enforcement that it would conduct an informal review with respect to certain issues addressed by the Division of Corporate Finance principally relating to the accounting for the capitalized financing costs related to the Company's investment in Seabrook Unit 1 and the effect which recording such amounts had on reported earnings for the three year period ended December 31, 1990. The Company informed the Division of Enforcement that it would cooperate with the informal inquiry and in July of 1991 the Company completed its responses to the Division of Enforcement's initial inquiries. The Company has received no communications from the Division of Enforcement since the Company completed its responses in July, 1991.

The Company restated its financial statements with respect to the amount of AFUDC recorded in 1988, 1989 and the first three quarters of 1990 which it believes addresses several issues raised by the SEC. The Company cannot predict the outcome of the SEC's review. The SEC could require that the Company further restate its financial statements for 1990, 1989 or 1988, or for any quarterly period during such years. The ultimate outcome of this matter cannot presently be determined and, accordingly, no provision for any adjustment that may result from its outcome has been made in the 1990 financial statements of the Company. The Company continues to believe that its financial statements (as previously restated) were prepared in accordance with generally accepted accounting principles and presented fairly the financial position and results of operations of the Company.

Other Proceedings

In June 1991, the State of New Hampshire imposed a Nuclear Station Property Tax applicable only to the Seabrook Project. The Company paid its share of the tax, aggregating $4.2 million through December 31, 1992. In October 1991 the Attorneys General of Connecticut, Massachusetts and Rhode Island petitioned the United States Supreme Court in an original jurisdiction case for a determination of the legality of the tax, and in January 1992 the Supreme Court agreed to take the case. The parties to the litigation and other Joint Owners of Seabrook entered into a Settlement Agreement on April 13, 1993. In general, the terms of the Settlement Agreement are expected to result in a significant reduction in annual state taxes paid by the Company. In addition, under the terms of the Settlement Agreement, certain of the prior payments of the tax by the Company will be permitted to be credited against future taxes due. The Bankruptcy Court has approved the Settlement Agreement with respect to the Company.

Schedule V

Great Bay Power Corporation
(f.k.a. EUA Power Corporation)
PROPERTY PLANT AND EQUIPMENT
(In Thousands)

COL. A Classification	COL. B Balance at Beginning of Period	COL. C Additions at Cost	COL. D Retirements	COL. E Other Charges Add (Deduct) – Describe	COL. F Balance at End of Period
For the Year Ended December 31, 1993:					
Production Nuclear	$497,726	$1,174	$1,263		$497,637
Transmission and Distribution	7,183				7,183
General Plant	5,981	75	31		6,025
Intangible Plant	926				926
Nuclear Fuel in Service	22,479				22,479
Construction Work in Progress	1,976	944			2,920
Nuclear Fuel in Process	349	2,156			2,505
Nuclear Fuel in Stock		2,505			2,505
Total Utility Plant	$536,620	$6,854	$1,294	$0	$542,180
For the Year Ended December 31, 1992:					
Production Nuclear	$499,597	$1,282	$130	($3,023) (a)	$497,726
Transmission and Distribution	7,243	4		(64)(a,b)	7,183
General Plant	5,885	132		(36) (a)	5,981
Intangible Plant	929			(3) (a)	926
Nuclear Fuel in Service	22,493	7,708	7,722		22,479
Construction Work in Progress	996	980			1,976
Nuclear Fuel in Process	4,524	(4,175)			349
Total Utility Plant	$541,667	$5,931	$7,852	($3,126)	$536,620
For the Year Ended December 31, 1991:					
Production Nuclear	$498,760	$1,862	$482	($543) (c)	$499,597
Transmission and Distribution	6,915	336		(8) (d)	7,243
General Plant	5,891			(6) (d)	5,885
Intangible Plant	930			(1) (d)	929
Nuclear Fuel in Service	19,230	7,272	4,009		22,493
Construction Work in Progress	1,039	(43)			996
Nuclear Fuel in Process	9,046	(4,522)			4,524
Total Utility Plant	$541,811	$4,905	$4,491	($558)	$541,667

(a) UE&C Settlement agreement ($557,949), Pre Operational Decommissioning ($1,558,158), Property Tax Abatement ($1,287,300), and Settlement Proceeds Fees $300,000.
(b) Includes ($22,914) transferred to cost of removal.
(c) Transfer pre-operational decommissioning trust funds from Plant in Service to Accounts Receivable.
(d) Transfer between accounts.

Great Bay Power Corporation
(f.k.a. EUA Power Corporation)

ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION OF PROPERTY, PLANT AND EQUIPMENT

(In Thousands)

Column A	Column B	Column C	Column D	Column E	Column F
Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Retirements	Other Charges Add (Deduct) – Describe	Balance at End of Period
For the Year Ended December 31, 1993: Accumulated Depreciation, Depletion and Amortization	$38,145	$19,684	$1,273	$0	$56,556
For the Year Ended December 31, 1992: Accumulated Depreciation, Depletion and Amortization	$25,751	$20,205	$7,811	$0	$38,145
For the Year Ended December 31, 1991: Accumulated Depreciation, Depletion and Amortization	$9,161	$21,108	$4,518	0	$25,751

Great Bay Power Corporation

Schedule IX

(f.k.a. EUA Power Croporation)
Short–Term Borrowings
(In Thousands)

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Category of aggregate short–term borrowings	Balance at end of period	Weighted Average Interest Rate	Maximum amount outstanding during the period	Average amount outstanding during the period (a)	Weighted average Interest rate during the period (b)
Notes Payable to Banks:					
December 31, 1993 (c)	$0	0.0%	$0	$0	0.0%
1992 (c)	$0	0.0%	$0	$0	0.0%
1991	$0	0.0%	$16,280	$2,517	7.4%

(a) The average amount outstanding during the period was comput. by .ividing the summation of the daily principal balances outstanding by 365.

(b) The weighted average interest rate during the period was computed by dividing the actual interest expense by the daily average short–term debt outstanding.

(c) Excludes amounts outstanding under the Debtor–in–Possession financing facility.

Great Bay Power Corporation
Supplementary Income Statement Information

Schedule X

COLUMN A	COLUMN B		
	For the Years Ended December 31,		
	1993	1992	1991
	Charged to Costs and Expense		
	(In Thousands)		
Taxes -- Other than Income:			
PAYROLL TAXES	$487	$498	$55
LOCAL PROPERTY TAXES	3,391	5,579	3,505
STATE CORPORATION TAXES	0	0	0
Charged to Operating Expenses	$3,878	$6,077	$3,560

Amounts of rents, advertising costs and research and development costs did not exceed 1% of gross revenues.

Amounts of maintenance and repairs and depreciation expense were as shown in the income statement and notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Director of Great Bay Power Corporation:

We have audited the financial statements and financial statement schedules of Great Bay Power Corporation (formerly EUA Power Corporation; the "Company") listed in item 14(a)(1) and (2) of this Form 10-K. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express our opinion on these financial statements and financial statement schedules based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1993 and 1992 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1993 in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedules referred to above, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information required to be included therein.

As discussed in Note H of "Notes to Financial Statements" under the heading "SEC Review", the Staff of the Securities and Exchange Commission (SEC) has reviewed certain reports previously filed with the SEC and has raised questions principally regarding the accounting for capitalized financing costs and could require that the Company further restate its financial statements.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note B of "Notes to Financial Statements," the Company filed a voluntary petition for protection under Chapter 11 of the Bankruptcy Code because it is currently selling power below its costs and has been unable to pay the debt service related to its Series B and Series C Secured Notes when due, all of which raise substantial doubt about its ability to continue as a going concern. The Company's plans in regard to these matters are also described in Note B. The financial statements do not include all of the adjustments that might result from the outcome of this uncertainty.

COOPERS & LYBRAND

Boston, Massachusetts
April 7, 1994