[1998 ANNUAL REPORT]

THEN now

defining the path to our future

UI

UI AT A GLANCE

1998 FIGURES

FINANCIAL PROFILE

Number of electric employees at year-end	1,011
Total payroll (000)	$65,294
Total taxes (000)	$112,937
Total operating revenue (000)	$686,191
Net utility plant at year-end (000)	$1,226,424
Fuel and energy cost (000)	$151,544
Shareowners (total)	14,735
In Connecticut	6,456

Number of shares outstanding at year-end	14,034,562
Income applicable to common stock (000)	$42,010
Earnings per share of common stock - Basic	$3.00
Earnings per share of common stock - Diluted	$3.00
Earnings per share from operations - Basic	$3.42
Dividends declared per share	$2.88
Payout ratio	96%
Return on average equity	9.44%
Book value per share	$31.74

CUSTOMER PROFILE

	Residential	Commercial	Industrial	Other	Total
Average number	281,591	29,468	1,752	1,172	313,983
kWh sales (000)	1,924,724	2,324,507	1,154,935	48,166	5,452,332
Sales revenue (000)	$262,974	$254,765	$102,201	$11,667	$631,607
Average revenue per kWh	13.66¢	10.96¢	8.85¢	24.22¢	11.58¢
Average kWh use per customer	6,835				
Peak load (mW)					1,143

UI GENERATING PROFILE

	Location	In-Service Date	Capacity (mW)	UI Share (mW)	%
FOSSIL CAPACITY					
Bridgeport Harbor Station	Bridgeport, CT	1961-1985	569.6	569.6	100%
New Haven Harbor Station	New Haven, CT	1975	466.0	436.7	93.71%
NUCLEAR CAPACITY					
Millstone Unit 3	Waterford, CT	1986	1,119.6	41.3	3.685%
Seabrook Unit 1	Seabrook, NH	1990	1,162.0	203.4	17.5%
RENEWABLE CAPACITY					
Hydro Quebec Entitlement	Canada	N/A	1,800.0	98.1	5.5%
Power Purchase: Refuse Recovery Generator	Bridgeport, CT	1988	59.5	59.5	100%

Average fuel cost per kWh generated	2.04¢
Generating capability at year-end (mW)	1,460
Barrels of oil burned (42gal/BBL)	4,586,983

Coal burned (tons)	589,574
Coal burned oil equivalent (BBL)	2,422,032
Gas burned (MCF)	49,600

TRANSMISSION AND DISTRIBUTION PROFILE

UI maintains approximately 102 circuit miles of overhead transmission lines and approximately 17 circuit miles of underground transmission cables. The Company owns and operates 25 bulk substations and 38 distribution substations. There are 3,170 pole-line miles of distribution lines and 130 conduit-bank miles of underground distribution lines in UI's system.

NATHANIEL D. WOODSON
Chairman, President and Chief Executive Officer

"Last year at this time, we were gearing up to fight once again for a fair and equitable restructuring law in Hartford."

THEN now

"Today, we have a new restructuring law and UI is positioned well for significant growth in the future."

defining the path to our future

A

DEAR SHAREOWNER:

1998 was a milestone year for The United Illuminating Company. We completed our first century of service to customers in the Greater Bridgeport and New Haven region, and we began a process of fundamental change that will transform what we do and how we do it in our next century.

As we undertake the exciting challenge of building a UI for the 21st century, we will measure success in two basic ways: Are we creating a company that can grow and thrive in the new, competitive energy world? And, are we delivering the kind of results that you, our shareowners, expect and deserve?

We know where we want to go, and we are charting the paths to

"There are tremendous opportunities ahead to create value in our business."

WHY CHANGE?

UI has been performing well for our customers and shareowners for a century. Today, however, our industry is experiencing dramatic change as electric energy markets open for competition for the first time in history. The Connecticut legislature passed a law to restructure the state's electric utility industry and allow electric energy suppliers to compete for retail customers. As part of this restructuring, regulated electric companies were required to divest the energy supply business if they wanted to recover costs incurred under regulation that the new market may not support. UI has such costs and reached an agreement to sell our generating stations.

The state Department of Public Utility Control (DPUC) is now moving ahead on implementing the law, addressing the more than 40 major issues that must be decided before consumers begin to choose their energy supplier. UI is actively participating in this implementation process, working to ensure that DPUC regulations are consistent with the legislative intent of the law.

The early decisions show some progress toward fairly implementing the legislation. The more difficult issues lie ahead of us, and we will continue our efforts to build on today's regulatory platform as we seek fair and equitable treatment for the new features in the law.

Change is here. These regulatory changes are critically important to us and to you, since they will be the cornerstones of the new competitive era. We know that to succeed in the new era, we must change as well.

TRANSFORMATION FOR A NEW ERA

We are building the foundation for our success by transforming ourselves. We have a clearly defined strategy for creating value for our shareowners and customers. We are moving faster and taking bold actions to assure that our shareowners, customers and communities are better served.

UI has been a vertically integrated utility — generating electricity, selling it, and delivering it to customers. As we concentrate on our competitive strengths and areas that offer the greatest

potential returns to our shareowners, vertical integration is becoming a thing of the past. Our future lies on a different path.

The new UI will be a premier regulated energy distribution company and a leading supplier of value-added energy services. We took a major step toward achieving this goal with the sale of our power generation business. In 1998, we completed a comprehensive auction process for our New Haven and Bridgeport generating stations and announced a buyer for these units — Wisvest of Wisconsin.

There are tremendous opportunities to create value in the regulated side of our business, by building the size of our core transmission and distribution operations. More than 40 electric

get there. UI will be an exciting place in the years to come.

and gas utilities currently serve customers in the Northeast region — not a very efficient or effective system. We are looking at combining smaller electric and gas distribution companies to be more effective in delivering services to customers. Consolidation is already underway. UI intends to be a proactive player in this arena.

We also see important growth opportunities for our two primary unregulated subsidiaries, American Payment Systems (APS) and Precision Power, Inc. (PPI). We are bringing in new, aggressive staff with track records of success in highly competitive industries to grow these two businesses.

APS is the nation's leading supplier of walk-in bill payment processing services for the utility industry. It has agents in 36 states and handled $7.5 billion in payments last year. We see this business as a unique engine of earnings growth among utility companies.

PPI has a bright future in providing energy-related equipment and services to owners of commercial, government and industrial buildings. Although we will no longer have a vested interest in where our customers buy the electricity they use, we will continue to have a vested interest in how successfully they use it. PPI is a valuable service provider that helps its customers get the highest return on their energy investments.

We also are evaluating further passive investments in two key projects for our region: the Bridgeport Energy combined cycle natural gas merchant plant co-owned by Duke Energy; and the Long Island Cable project, co-owned by a subsidiary of Hydro Quebec. The cable project will connect southern New England to Long Island under a long-term rights agreement with the Long Island Power Authority (LIPA).

MANAGING THE TRANSITION TO OUR SECOND CENTURY

We have a vision for the future and are putting the key components in place to achieve it. But we also have a day-to-day business to run. Our success in transforming UI for the new era will depend on our success at keeping our customers and shareowners satisfied day in and day out.

We are working hard not only to meet, but exceed customer expectations in all our business ventures. As a company, we are aiming at the highest standards of operational and func-

tional excellence. Every UI organization and discipline has benchmarked competitors, and has put plans in place to become one of the industry's top-ranking performers.

As we improve performance, we are also increasing sales. In 1998, UI achieved an all-time high in electric sales — 5,452,000,000 kilowatt-hours. The increase reflected the strong regional economy and warmer than usual weather, and occurred even though Yale University reduced its consumption by 30 percent as a result of its power cogeneration project.

NATHANIEL D. WOODSON

For our shareowners, 1998 was another year of solid stock price appreciation. Investor confidence continued to grow as the industry restructuring situation clarified. Our stock price reached a 10-year high of 53¾, before ending the year at 51½. Total shareowner return for the year, including dividends, was more than 18 percent.

On a diluted basis, earnings for 1998 were $42 million, or $3.00 per share. Excluding the full effect of one-time items, earnings from operations were $4 million, or $3.42 a share, up 10 percent from 1997. Cash flow continued at high levels in 1998.

Last year was the second under our innovative rate plan, which allows an 11.5 percent utility equity return, accelerates asset recovery, and reduces customer bills. Under the rate plan, the Company was able to accelerate the non-cash amortization of pre-tax regulatory costs by more than $13 million, and provide additional price reductions for customers. And to date, UI customers have received price reductions of about five percent since December 1996.

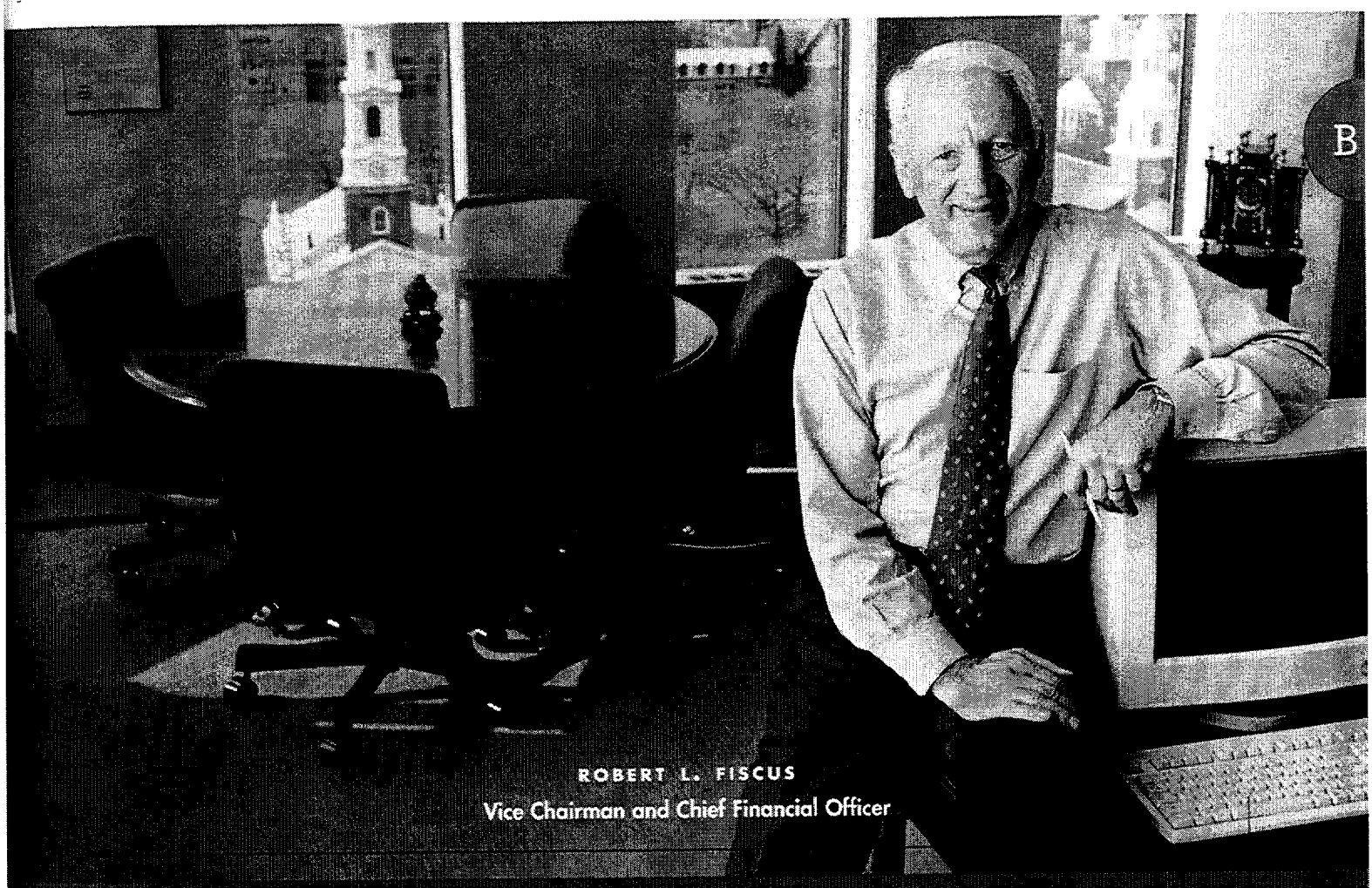
LOOKING TO THE FUTURE

What a difference a year makes. One year ago, Chairman and CEO Dick Grossi told you we were gearing up to fight once again for a fair and equitable electric industry restructuring law in Hartford. Today, we have a new restructuring law, Dick has retired as Chairman and CEO, and I have been on the job 12 months.

After a year on the job, I am convinced that UI is positioned well for significant growth in the future.

We know where we want to go, and we are charting the paths to get there. UI will be an exciting place in the years to come, and we look forward to playing an important role in the future of this region. We have a challenging task ahead of us, but I know we are up to it and you, our shareowners, will be pleased with the results.

Chairman, President and Chief Executive Officer



ROBERT L. FISCUS
Vice Chairman and Chief Financial Officer

"We've spent years building the financial strength we need to carry out our business strategy. And we're supplementing our existing systems and expertise to be competitive in the new environment. We're confident our systems, people and financial resources are aligned to achieve success."

SUMMARY FINANCIAL information

B

Glossary of Terms

AFTER-TAX The effect that an item of income or expense has on earnings after the impact of state and federal income taxes; the combined statutory income tax rate on UI was about 41.175% in 1998.

AMORTIZATION The accounting process of decreasing the book value of an intangible asset by periodic non-cash charges against income over a specified time period.

AMORTIZATION OF SEABROOK PHASE-IN COSTS The amortization in 1995 to 1999 of deferred Seabrook-related income accrued during its phase-in to rate base during 1990 to 1993.

BOOK VALUE PER SHARE Calculated by dividing "Total Common Stock Equity" by "Common Shares Outstanding."

CAPACITY FACTOR A measure of the energy actually produced by a generating system over a period of time relative to maximum amount of energy that the system was capable of producing during that time period.

CONSERVATION ADJUSTMENT MECHANISM A component of retail customer rates that allows the Company to recover its expenditures for approved conservation and load management programs.

CASH FLOW Net cash provided by operating activities as shown on the "Consolidated Statement of Cash Flows."

DEFERRING The process of delaying the recognition of an expense transaction for accounting purposes until some time in the future.

DPUC Department of Public Utility Control — the governmental body that regulates the activities of the Company.

EARNINGS PER SHARE "Income Applicable to Common Stock" divided by "Average Number of Common Shares Outstanding."

EARLY RETIREMENT CHARGES A one-time recording of the expenses associated with an early retirement program offering to employees.

EARNINGS PER SHARE FROM OPERATIONS Earnings per share, excluding the effects of non-recurring items of income or expense.

ELECTRIC UTILITY DEREGULATION The process of removing governmental controls over the electric industry and allowing the utility companies to operate in a free market with no defined territories and open to competition.

EQUITY CAPITALIZATION RATIO The ratio of "Common Stock Equity" to "Total Capitalization."

FREE CASH FLOW Net cash from operating activities less dividend payments and capital expenditures; cash available to pay down debt.

GROSS EARNINGS TAX A Connecticut tax (approximately 3.8% on average in 1998) assessed on all of a utility's retail revenues.

kWh The energy consumed by ten 100-watt light bulbs operating for one hour; mWh = Megawatt hour or 1,000 kWhs; gWh = Gigawatt hour or 1,000,000 kWhs.

LOAD FACTOR A measure of the kWh consumed by a retail system over a period of time relative to the kWhs it would have consumed if its rate of consumption during the entire period had equaled its maximum rate of consumption at any time during the period.

NEPOOL New England Power Pool.

NON-RECURRING An income or expense item that is a "one-time" event — e.g., a gain from the sale of property or an early retirement charge.

PAYOUT RATIO Cash dividends declared per share of common stock divided by earnings per share.

RATE PLAN A five-year plan offered by the DPUC and implemented by the Company in 1996 that allowed the Company to earn an annual equity return of 11.5% over the five-year period and to share any earnings above that level. The plan also provides for annual increases in the accelerated amortization of some regulatory assets, although earnings need to be at least 10.5% for the accelerated charges to be taken.

REGULATORY ASSETS A balance sheet asset consisting of the right to collect certain revenues in the future.

RETAIL WHEELING The selling of electricity to an end user in a utility's retail franchise territory by a person other than that utility.

SALES MARGIN Revenues less fuel expense and Connecticut's tax on revenues.

SEABROOK The nuclear generating unit located in Seabrook, New Hampshire, which is jointly owned by UI and other New England electric utility entities.

SEABROOK REFUELING The period when Seabrook is unavailable to produce electricity while a portion of its nuclear fuel is being replaced.

SECURITIZATION A form of state-assisted debt financing that may allow the Company to lower costs and further enhance customer price reductions.

STRANDED COSTS Past investments in plant that may not be recoverable in the new competitive power market environment. Also known as transition assets.

TOTAL RETURN Cash dividends declared per share of Common Stock over a period of time, plus (or minus) the increase (or decrease) in the market price per share of Common Stock between the beginning and the end of the period.

UNBUNDLED RATES The rates that separately identify (a) charges for generation, transmission and distribution services; (b) charges for energy efficiency and renewable resources; (c) the transition charge; (d) the systems benefits charge; and (e) any other miscellaneous charges.

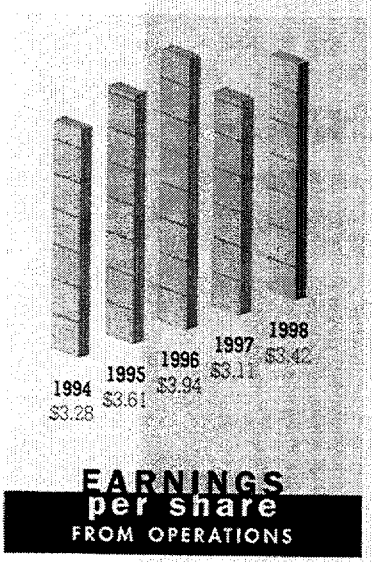
UNBUNDLING The breaking down of electric utility services into its component parts (i.e., generation, transmission and distribution services) so that each part can be sold or billed separately.

B

Summary Results of Operation

I. Earnings Under Five-Year Rate Plan ("The Rate Plan")

The Company's principal regulated electric utility business is operating under a five-year Rate Plan that began in 1997 and goes through 2001. The Rate Plan allows for an equity return of 11.5% on rate base equity and a sharing mechanism that allows the Company to earn above 11.5% if operating margins improve over anticipated levels. The Rate Plan also provides for annual increases in accelerated amortization, although earnings need to be at least 10.5% for these charges to be taken.



EARNINGS FROM OPERATIONS Total earnings may fluctuate due to various non-recurring items. Looking at "earnings from operations," which exclude non-recurring items, is a useful way to evaluate year-to-year trends and build expectations for the future years.

Earnings from operations in 1998 were $3.42 per share, up $.31 per share from 1997. The increase was due largely to increased "real" retail sales growth.

TOTAL EARNINGS Total earnings per share for 1998 were $3.00, down $.27 per share from the 1997 level of $3.27. Earnings in each of the years 1994-1998 were affected by various non-recurring items that, if not segregated, produce a view of recent earnings trends that is different from the view provided by earnings from operations:

- **1998** Charges related to subsidiary losses and a property tax settlement with the City of New Haven, offset by a refund of prior period transmission charges, accounted for a net $.42 per share decrease in earnings.
- **1997** Net gains, principally from deferred income tax benefits, partially offset by accelerated amortization of regulatory assets and a charge for the termination of a contract, increased earnings by $.16 per share.
- **1996** Charges related to two early retirement programs, a severance program and a subsidiary loss, offset by a gain from the purchase of preferred stock at a discount, reduced earnings by $1.06 per share.
- **1995** A charge to reflect the effects of legislated future state income tax rate reductions and a gain from the repurchase of preferred stock at a discount, increased earnings by $.03 per share.
- **1994** The settlement of a property tax dispute with the City of Bridgeport and an accounting change to reflect the accrual of postemployment benefits, reduced earnings by $.19 per share.

II. Why Earnings from Operations Increased in 1998

Retail operating revenues increased by about $8 million, which was principally due to an increase in "real" retail sales growth. This increase was offset by an increase of $7.2 million in retail fuel and energy expense, principally from increased sales, the need to purchase more expensive fossil energy to replace generation from the unscheduled outage at Bridgeport Harbor Unit 3 and an increase in the price of fossil fuel. Other operating revenues and retail sales margin increased by $5.8 million, primarily because NEPOOL related transmission revenues, which previously were booked as credits to operation expense, are now shown as revenues.

	1998	1997
Earnings per share — Basic		
From operations	$3.42	$3.11
From non-recurring items	(.42)	.16
Total earnings per share	$3.00	$3.27

Net wholesale margin increased slightly in 1998.

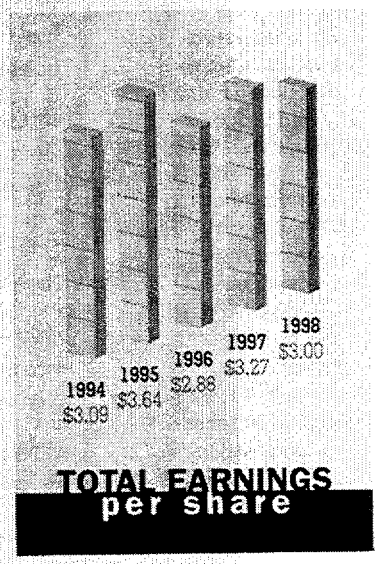
Operating expenses for operations, maintenance and purchased capacity charges decreased by $15.0 million in 1998 compared to 1997, principally due to reduced capacity expenses associated with Connecticut

Yankee and reduced operation and maintenance expenses associated with Seabrook, Millstone Unit 3 and personnel reductions. These decreases were offset by increases in operating expenses due to the unscheduled overhaul at Bridgeport Harbor Unit 3. Depreciation expense, excluding accelerated amortization, increased by $1.5 million. Interest charges decreased by $10.4 million as a result of the Company's refinancing program and strong cash flow.

B

III. Looking Forward

1999 will be a transition year for the Company as it prepares for the January 1, 2000 effective date for electric utility restructuring. The Company has already taken one major step in preparing for electric utility restructuring — the sale of its operating fossil fuel generation plants, which is expected to close in the spring. One result of the sale will be the reduction in the Company's electric utility rate base. During 1998, a return of 11.5% on utility common stock equity would have produced earnings of about $3.43 per share. Because of the rate base reduction expected in 1999, the allowed return is expected to produce utility earnings in the $3.35-$3.40 per share range.



OPERATION AND MAINTENANCE EXPENSE The Company expects substantial net expense reductions as a result of the generation asset sale and the ongoing cost control measures. These savings should more than compensate for the increased charges for purchased power incurred as a result of the elimination of our generating capability and increased accelerated amortization charges required under the plan. Such performance should allow utility earnings to increase above an 11.5% return on common stock equity into the "sharing" range of the Rate Plan. This shared earnings benefit is currently anticipated to contribute about $.20 per share.

SALES GROWTH The Company experienced about 1% - 1.5% of weather adjusted "real" sales growth in 1998. A similar level of growth in 1999 from all customer groups would add about $5 - $7.5 million to sales margin. UI's largest customer commenced operation of a cogeneration unit in mid-1998, which has reduced total Company retail kilowatt-hour sales by 0.9% in 1998. The remaining impact will be reflected in the first half of 1999. As a result, it would require real growth of 0.5% in 1999 to maintain the 1998 level of real sales.

INTEREST COSTS The Company plans to use the net after-tax proceeds from the sale of its fossil-fuel generating plants to pay down debt. The Company also expects to generate substantial cash flow from operations, after dividend and capital spending, which will also be used to pay down debt. As a result, interest costs are expected to decline by about $14 million, in 1999 compared to 1998, to about $38 million, a level last visited in 1982.

OTHER EXPENSES Depreciation expense should decrease by about $13 million in 1999 compared to 1998. Accelerated amortization, per the Rate Plan, will increase by about $7 million. Property taxes should decrease by about $2 million, due mostly to the generation asset sale. Other operating expenses can be expected to have some increases and some decreases that should, more or less, offset one another.

UNREGULATED EARNINGS Unregulated subsidiaries are expected to experience a loss of up to $.10 per share to earnings in 1999. American Payment Systems, Inc. is expected to improve on its 1998 earnings of $.07 per share, but Precision Power, Inc. is expected to lose $.10 to $.15 per share due to expansion of infrastructure and possible acquisitions.

In summary, the Company expects net earnings per share from operation to be in the range of $3.45 to $3.65 per share in 1999.

B

Condensed Consolidated Statement of Income

For the Years Ended December 31, 1998 & 1997

This statement is a summary of the Company's operating performance that shows the Company's revenues and expenses that result in the "Balance for Common Stock," the earnings for all shareowners.

(In Millions of Dollars Except Per Share Amounts)	1998	1997
OPERATING REVENUES	$686	$710
Fuel and energy expense	152	183
Sales-related taxes	23	23
SALES MARGIN	511	504
Operation expenses	252	269
Depreciation and amortization	96	82
Non-recurring charges	16	7
Other (income) and expenses	5	(1)
Interest expense	52	62
INCOME BEFORE INCOME TAXES	90	85
Income taxes for operations	54	48
Non-recurring income taxes	(6)	(9)
NET INCOME	42	46
Preferred stock dividends	-	-
INCOME APPLICABLE TO COMMON STOCK	$42	$46
AVERAGE NUMBER OF SHARES OUTSTANDING	14	14
EARNINGS PER SHARE - BASIC	$3.00	$3.27
EARNINGS PER SHARE - DILUTED	$3.00	$3.26

Includes operation, maintenance, purchased capacity and property and payroll taxes

Includes about $13 million of amortization of previously deferred revenue and, in 1998, $13 million of accelerated amortization of conservation costs

The Company's refinancing program and strong cash flow help to reduce interest expense

Non-recurring charges for 1998 include, principally, $5 million for a subsidiary loss, $14 million for a property tax settlement, offset by $3 million for a one-time refund. In 1997, the principal amounts were for accelerated amortization and income tax benefits

Reflects regulatory requirement to reflect certain expense credits as revenue in 1998

Reflects lower sales in wholesale market

	1998	1997
Retail Operating Revenue	$632	$623
Other Operating Revenue	9	4
Retail fuel and energy expense	117	110
Sales-related taxes	23	23
Retail Sales Margin	$501	$494
Wholesale Operating Revenue	$45	$83
Wholesale fuel & energy expense	35	73
Wholesale Sales Margin	$10	$10

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1998, including the report of independent accountants, dated February 12, 1999, in the Annual Report to Shareowners.

Condensed Consolidated Balance Sheet

December 31, 1998 & 1997

This statement reports the Company's total assets (what we own and what is owed to us), liabilities (what we owe others, now and in the future) and capitalization (amounts invested in or loaned to the Company) at the end of the year.

(In Millions of Dollars)	1998	1997
ASSETS		
UTILITY NET PLANT AT ORIGINAL COST	$1,172	$1,222
CONSTRUCTION WORK IN PROGRESS	34	26
NUCLEAR FUEL	20	26
OTHER PROPERTY AND INVESTMENTS	38	33
CURRENT ASSETS		
Cash and temporary cash investments	101	32
Customer accounts receivable, net and accrued utility revenues	75	83
Other	79	50
TOTAL	255	165
DEFERRED CHARGES	11	12
REGULATORY ASSETS	361	396
	$1,891	$1,880
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
Common stock equity	$445	$439
Preferred stock	4	4
Preferred securities	50	50
Long-term debt - net	665	645
TOTAL	1,164	1,138
NON-CURRENT LIABILITIES	110	120
CURRENT LIABILITIES		
Current portion of long-term debt	66	100
Notes payable	87	38
Accounts payable	53	69
Other	70	62
TOTAL	276	269
REGULATORY LIABILITIES	18	18
DEFERRED INCOME TAXES	321	333
OTHER	2	2
COMMITMENTS AND CONTINGENCIES	-	-
	$1,891	$1,880

Includes inventory, prepayments and receivables for interest, miscellaneous billings and subsidiaries

Principally unamortized debt issuance costs

Future revenues due from customers through the ratemaking process, principally to collect future income taxes

Includes Connecticut Yankee obligation, pensions accrued and accrued nuclear decommissioning costs

Includes dividends payable, taxes accrued and interest accrued

Future amounts owed to customers through the ratemaking process

Future tax liabilities owed to taxing authorities from future customer revenues

Shareowners' "book" value
1998: $31.74 per share
1997: $31.56 per share

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1998, including the report of independent accountants, dated February 12, 1999, in the Annual Report to Shareowners.

B

Condensed Consolidated Statement of Cash Flows

For the Years Ended December 31, 1998 & 1997

This statement is a summary of cash inflows and outflows during the year from operating, investing and financing activities

These amounts are included in the calculation of net income, but do not represent cash outflows

Working capital increased in 1998 because we paid some current obligations and ended a fuel lease arrangement

Investment in our own debt securities in 1996 and 1997 to reduce overall interest expense. Investment amount reduced in 1998

(In Millions of Dollars)	1998	1997
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$42	$46
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	101	92
Deferred income taxes	1	8
Amortization of nuclear fuel	7	6
Other non-cash income items	(1)	(2)
Subtotal	150	150
Cash (used for) provided by working capital changes	(40)	19
Cash Provided by Operating Activities	110	169
Dividend payments	(41)	(41)
Cash used for debt and equity redemptions	(222)	(151)
Cash provided by debt/equity issuances and borrowings	251	117
Cash (used for) provided by investments	9	(35)
Cash used for capital expenditures	(38)	(33)
INCREASE IN CASH AND TEMPORARY CASH INVESTMENTS	69	26
CASH BALANCE AT BEGINNING OF PERIOD	32	6
CASH BALANCE AT END OF PERIOD	$101	$32

	1998	1997
Cash Available from Earnings to Pay Interest Charges (A)	$161	$228
Annual Cash Interest Charges (B)	51	59
Total Debt (C)	731	745
Cash Coverage Ratio (A)/(B)	3.2	3.9
Cash Available to Total Debt (A-B)/(C)	15%	23%

	1998	1997
Cash Provided by Operating Activities less Dividend Payments	$69	$128
Capital Expenditures	(38)	(33)
Difference	$31	$95

These condensed financial statements should be read in conjunction with the full financial statements for the year ended December 31, 1998, including the report of independent accountants, dated February 12, 1999, in the Annual Report to Shareowners.

Financial and Stock Data

INCOME & DIVIDEND DATA

Year	Sales Margin $mil	Sales Margin $/share	Pretax (fed.) Net Income $mil	Pretax (fed.) Net Income % of s.m.	Balance for Common $mil	Basic Earnings per share $	Diluted Earnings per share $	Dividend Declared per share $	Payout ratio %	Yield on Average price %
1994	502	35.64	81	16.1	43	3.09	3.08	2.76	89.3	8.1
1995	525	37.25	92	17.5	51	3.64	3.63	2.82	77.5	8.3
1996	539	38.21	74	13.7	41	2.88	2.87	2.88	100.0	8.1
1997	504	36.06	76	15.1	46	3.27	3.26	2.88	88.1	8.2
1998	511	36.42	80	15.6	42	3.00	3.00	2.88	96.0	6.0
5 Yr. Avg	516	36.72	81	15.6	45	3.18	3.17	2.84	90.2	7.7

COMMON SHARE DATA

Year	Closing Price Range $ High	Closing Price Range $ Low	Closing Price Range $ End	Price Earnings Ratio High	Price Earnings Ratio Low	Price Earnings Ratio Close
1994	39 1/2	29	29 1/2	12.8	9.4	9.5
1995	38 1/2	29 1/2	37 3/8	10.6	8.1	10.3
1996	39 3/4	31 3/8	31 3/8	13.8	10.9	10.9
1997	45 15/16	24 1/2	45 15/16	14.0	7.5	14.0
1998	53 3/4	42 5/8	51 1/2	17.9	14.2	17.2
5 Yr. Avg.	43 1/2	31 6/16	39 1/8	13.8	10.0	12.4

COMMON SHARE DATA (CONT'D)

Quarter ended	Closing Market Price $ 1998 High	1998 Low	1998 End	1997 High	1997 Low	1997 End	1996 High	1996 Low	1996 End	Trading Volume in Thousands 1998	1997	1996
3/31	48 9/16	42 5/8	48 3/8	32 5/8	24 1/2	26 1/8	39 3/4	36 1/4	36 7/8	2,874	4,990	4,023
6/30	51 15/16	46 15/16	50 5/8	30 7/8	24 1/2	30 7/8	38	35 3/4	37 3/8	2,631	4,660	2,534
9/30	53 9/16	49	52 1/4	37	31 1/2	36 7/16	37 1/2	33 7/8	34 3/8	2,183	4,032	1,801
12/31	53 3/4	48 1/16	51 1/2	45 15/16	37	45 15/16	35	31 3/8	31 3/8	1,382	2,710	3,020

QUARTERLY FINANCIAL INFORMATION

Quarter ended	Sales Margin $ mil. 1998	Sales Margin $ mil. 1997	Sales Margin $ mil. 1996	Pretax (fed.) Net Income $ mil. 1998	Pretax (fed.) Net Income $ mil. 1997	Pretax (fed.) Net Income $ mil. 1996	Basic Earnings per Share $ 1998	Basic Earnings per Share $ 1997	Basic Earnings per Share $ 1996	Dividends Paid per Share $ 1998	Dividends Paid per Share $ 1997	Dividends Paid per Share $ 1996
3/31	116	120	133	18	15	21	0.64	0.54	0.82	0.72	0.72	0.705
6/30	121	119	129	12	8	18	0.39	0.61	0.75	0.72	0.72	0.72
9/30	152	146	153	45	40	31	1.87	1.68	1.27	0.72	0.72	0.72
12/31	122	119	124	5	13	4	0.10	0.44	0.04	0.72	0.72	0.72

s.m. = Sales Margin; (fed.) = Federal

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1998 ANNUAL REPORT to shareowners

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Major Influences on Financial Condition

The Company's financial condition will continue to be dependent on the level of its retail and wholesale sales and the Company's ability to control expenses. The two primary factors that affect sales volume are economic conditions and weather. Total operation and maintenance expense, excluding one-time items and cogeneration capacity purchases, declined by 1.1 percent, on average, during the past five years. There will be significant changes to operation and maintenance expense and other expenses in 1999, partly as a result of the Generation Asset Divestiture (see "Looking Forward.")

The Company's financial status and financing capability will continue to be sensitive to many other factors, including conditions in the securities markets, economic conditions, interest rates, the level of the Company's income and cash flow, and legislative and regulatory developments, including the cost of compliance with increasingly stringent environmental legislation and regulations, and competition within the electric utility industry.

On December 31, 1996, the DPUC completed a financial and operational review of the Company and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The DPUC did not change the existing retail base rates charged to customers; but the Rate Plan increased amortization of the Company's conservation and load management program investments during 1997-1998, and accelerated the amortization and recovery of unspecified assets during 1999-2001 if the Company's common stock equity return on utility investment exceeds 10.5% after recording the amortization. The Rate Plan also provided for retail price reductions of about 5%, compared to 1996 and phased-in over 1997-2001, primarily through reductions of conservation adjustment mechanism revenues, through a surcredit in each of the five plan years, and through acceptance of the Company's proposal to modify the operation of the fossil fuel clause mechanism. The Company's authorized return on utility common stock equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are to be utilized one-third for customer price reductions, one-third to increase amortization of regulatory assets, and one-third retained as earnings. As a result of the Rate Plan, customer prices were required to be reduced, on average, by 3% in 1997 compared to 1996. Also as a result of the Rate Plan, customer prices are required to be reduced by an additional 1% in 2000, and another 1% in 2001, compared to 1996. Retail revenues have decreased by approximately 4.8% through 1998 compared to 1996 due to customer price reductions. The Rate Plan was reopened in 1998, in accordance with its terms, to determine the assets to be subjected to accelerated recovery in 1999, 2000 and 2001. The DPUC decided on February 10, 1999 that $12.1 million of the Company's regulatory tax assets will be subjected to accelerated recovery in 1999. The DPUC has not yet determined the assets to be subjected to recovery after 1999. The Rate Plan also includes a provision that it may be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut and, as a consequence of the 1998 Restructuring Act described below, the Rate Plan may be reopened and modified. However, aside from implementing an additional price reduction in 2000 to achieve the minimum 10% price reduction required by the Restructuring Act and the probable reductions in the accelerated amortizations scheduled in the Rate Plan, the Company is unable to predict, at this time, in what other respects the Rate Plan may be modified on account of this legislation.

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. The business of generating and supplying electricity directly to consumers will be price-deregulated and opened to competition beginning in the

year 2000. At that time, these business activities will be separated from the business of delivering electricity to consumers, also known as the transmission and distribution business. The business of delivering electricity will remain with the incumbent franchised utility companies (including the Company), which will continue to be regulated by the DPUC as Distribution Companies. Beginning in 2000, each retail consumer of electricity in Connecticut (excluding consumers served by municipal electric systems) will be able to choose his, her or its supplier of electricity from among competing licensed suppliers, for delivery over the wires system of the franchised Distribution Company. Commencing no later than mid-1999, Distribution Companies will be required to separate on consumers' bills the charge for electricity generation services from the charge for delivering the electricity and all other charges. On July 29, 1998, the DPUC issued the first of what are expected to be several orders relative to this "unbundling" requirement, and has now reopened its proceeding to consider the amount of the generation services charge to be included on consumers' bills.

A major component of the Restructuring Act is the collection, by Distribution Companies, of a "competitive transition assessment," a "systems benefits charge," an "energy conservation and load management program charge" and a "renewable energy investment charge". The competitive transition assessment represents costs that have been reasonably incurred by, or will be incurred by, Distribution Companies to meet their public service obligations as electric companies, and that will likely not otherwise be recoverable in a competitive generation and supply market. These costs include above-market long-term purchased power contract obligations, regulatory asset recovery and above-market investments in power plants (so-called stranded costs). The systems benefits charge represents public policy costs, such as generation decommissioning and displaced worker protection costs. Beginning in 2000, a Distribution Company must collect the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge from all Distribution Company customers, except customers taking service under special contracts pre-dating the Restructuring Act. The Distribution Company will also be required to offer a "standard offer" rate that is, subject to certain adjustments, at least 10% below its fully bundled prices for electricity at rates in effect on December 31, 1996, as discussed below. The standard offer is required, subject to certain adjustments, to be the total rate charged under the standard offer, including generation and transmission and distribution services, the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge.

The Restructuring Act requires that, in order for a Distribution Company to recover any stranded costs associated with its power plants, its fossil-fueled plants must be sold prior to 2000, with any net excess proceeds used to mitigate its recoverable stranded costs, and the Company must attempt to divest its ownership interest in its nuclear-fueled power plants prior to 2004. By October 1, 1998, each Distribution Company was required to file, for the DPUC's approval, an "unbundling plan" to separate, on or before October 1, 1999, all of its power plants that will not have been sold prior to the DPUC's approval of the unbundling plan or will not be sold prior to 2000.

In May of 1998, the Company announced that it would commence selling, through a two-stage bidding process, all of its non-nuclear generation assets, in compliance with the Restructuring Act. On October 2, 1998, the Company agreed to sell both of its operating fossil-fueled generating stations, Bridgeport Harbor Station and New Haven Harbor Station, to Wisvest-Connecticut, LLC, a single-purpose subsidiary of Wisvest Corporation. Wisvest Corporation is a non-utility subsidiary of Wisconsin Energy Corporation, Milwaukee, Wisconsin. The sale price is $272 million in cash, including payment for some non-plant items, and the transaction is expected to close during the spring of 1999. It is contingent upon the receipt of approvals from the DPUC, the Federal Energy Regulatory Commission (FERC), and other federal and state agencies.

A petition seeking the DPUC's approval was filed on October 30, 1998 and, on March 5, 1999, the DPUC issued a decision approving the sale. An application seeking the FERC's authorization for the sale of the facilities subject to its jurisdiction was filed on December 21, 1998 and, on February 24, 1999, the FERC issued an order authorizing the sale.

The Company will realize a book gain from the sale proceeds net of taxes and plant investment. However, this gain will be offset by a writedown of other above-market generation costs eligible for the competitive transition assessment, such as regulated plant costs and tax-related regulatory assets or other costs related to the restructuring transition, such that there will be no net income effect of the sale. Net cash proceeds from the sale are expected to be in the range of $160-$165 million. The Company anticipates using these proceeds to reduce debt.

The October 2, 1998 sale agreement for Bridgeport Harbor Station and New Haven Harbor Station resulted from a bidding process. The Company's only other fossil-fueled generating station is its small deactivated English Station, in New Haven. English Station was also offered for sale in the bidding process, but it attracted no bids. Also offered for sale were two long-term contracts for the purchase of power from refuse-to-energy facilities located in Bridgeport and Shelton, Connecticut, one long-term contract for the purchase of power from a small hydroelectric generating station located in Derby, Connecticut, and the Company's 5.45% participating share in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. None of these contracts attracted an acceptable bid.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, the Company stated that it plans to divest its nuclear generation ownership interests (17.5% of Seabrook Station in New Hampshire and 3.685% of Millstone Station Unit No. 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. The divestiture method has not yet been determined. In anticipation of ultimate divestiture, the Company proposed to satisfy, on a functional basis, the Restructuring Act's requirement that nuclear generating assets be separated from its transmission and distribution assets. This would be accomplished by transferring the nuclear generating assets into a separate new division of the Company, using divisional financial statements and accounting to segregate all revenues, expenses, assets and liabilities associated with nuclear ownership interests.

The Company's unbundling plan also proposes to separate its ongoing regulated transmission and distribution operations and functions, that is, the Distribution Company assets and operations, from all of its unregulated operations and activities. This would be achieved by undergoing a corporate restructuring into a holding company structure. In the holding company structure proposed, the Company will become a wholly-owned subsidiary of a holding company, and each share of the common stock of the Company will be converted into a share of common stock of the holding company. In connection with the formation of the holding company structure, all of the Company's interests in all of its operating unregulated subsidiaries will be transferred to the holding company and, to the extent new businesses are subsequently acquired or commenced, they will also be financed and owned by the holding company. An application for the DPUC's approval of this corporate restructuring was filed on November 13, 1998. DPUC hearings on the corporate unbundling plan and corporate restructuring commenced on February 18, 1999.

Under the Restructuring Act, all Connecticut electricity customers will be able to choose their power supply providers after June 30, 2000. The Company will be required to offer fully-bundled service to customers under a regulated "standard offer" rate and will also become the power supply provider to each customer who does not choose an alternate power supply provider, even though the Company will no longer be in the business of retail power generation. In order to mitigate the financial risk that these regulated service mandates will pose to the Company in an unregulated power generation environment, its unbundling plan

proposes that a purchased power adjustment clause be added to its regulated rates, effective July 1, 2000, as permitted by the Restructuring Act. This clause, similar to and based on the purchased gas adjustment clauses used by Connecticut's natural gas local distribution companies, would work in tandem with the Company's procurement of power supplies to assure that "standard offer" customers pay competitive market rates for power supply services and that the Company collects its costs of providing such services. The Distribution Company is also required under the Restructuring Act to provide back-up power supply service to customers whose electric supplier fails to provide power supply services for reasons other than the customers' failure to pay for such services. The Restructuring Act provides for the Distribution Company to recover its reasonable costs of providing this back-up service.

In addition to approval by the DPUC, the several features of the Company's unbundling plan will be subject to approvals and consents by federal regulators, other state and federal agencies, and the Company's common stock shareowners.

On and after January 1, 2000 and until January 1, 2004, the Company will be responsible for providing a standard offer service to customers who do not choose an alternate electricity supplier. The standard offer prices, including the fully-bundled price of generation, transmission and distribution services, the competitive transition assessment, the systems benefits charge and the energy conservation and renewable energy assessments, must be at least 10% below the average fully-bundled prices in effect on December 31, 1996. The Company has already delivered about 4.8% of this decrease, in price reductions through 1998. The DPUC's 1996 financial and operational review order anticipated sufficient income in 2000 to accelerate amortization of regulatory assets of about $50 million, equivalent to about 8% of retail revenues. Substantially all of this accelerated amortization may have to be eliminated to allow for the additional standard offer price reduction requirement of 10%, at a minimum, while providing for the added costs imposed by the restructuring legislation. The legislation does prescribe certain bases for adjusting the price of standard offer service if the 10% minimum price reduction cannot be accomplished.

Currently, the Company's electric service rates are subject to regulation and are based on the Company's costs. Therefore, the Company, and most regulated utilities, are subject to certain accounting standards (Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71)) that are not applicable to other businesses in general. These accounting rules allow a regulated utility, where appropriate, to defer the income statement impact of certain costs that are expected to be recovered in future regulated service rates and to establish regulatory assets on its balance sheet for such costs. The effects of competition or a change in the cost-based regulatory structure could cause the operations of the Company, or a portion of its assets or operations, to cease meeting the criteria for application of these accounting rules. The Company expects to continue to meet these criteria in the forseeable future. The Restructuring Act enacted in Connecticut in 1998 provides for the Company to recover in future regulated service rates previously deferred costs through ongoing assessments to be included in such rates. If the Company, or a portion of its assets or operations, were to cease meeting these criteria, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs are not recoverable in that portion of the business that continues to meet the criteria for the application of SFAS No. 71. If this change in accounting were to occur, it would have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well.

Liquidity and Capital Resources

The Company's capital requirements are presently projected as follows:

(In Millions of Dollars)	1999	2000	2001	2002	2003
Cash on Hand - Beginning of Year	$101.4	$34.5	$9.0	$42.7	$ -
Internally Generated Funds less Dividends	98.4	59.4	57.4	64.4	72.7
Net Proceeds from Sale of Fossil Generation Plants	160.0	-	-	-	-
Subtotal	359.8	93.9	66.4	107.1	72.7
Less:					
Capital Expenditures (excluding AFUDC)	30.7	34.5	23.4	18.9	23.3
Cash Available to pay Debt Maturities and Redemptions	329.1	59.4	43.0	88.2	49.4
Less:					
Maturities and Mandatory Redemptions	69.6	0.4	0.3	100.3	100.5
Optional Redemptions	145.0	50.0	-	-	-
Repayment of Short-Term Borrowings	80.0	-	-	-	-
External Financing Requirements (Surplus)	$(34.5)	$(9.0)	$(42.7)	$12.1	$51.1

Note: Internally Generated Funds less Dividends, Capital Expenditures and External Financing Requirements are estimates based on current earnings and cash flow projections, including the implementation of the legislative mandate to achieve a 10% price reduction from December 31, 1996 price levels by the year 2000. Connecticut's Restructuring Act, described in "Major Influences on Financial Condition," requires the Company to divest itself of its fossil-fueled generating plants prior to January 1, 2000 and to attempt to divest itself of its ownership interests in nuclear-fueled generating units prior to January 1, 2004. This forecast reflects the estimated net after-tax proceeds ($160-$165 million) from a proposed divestiture of fossil-fueled generation plants on or about April 1, 1999. All of these estimates are subject to change due to future events and conditions that may be substantially different from those used in developing the projections.

All of the Company's capital requirements that exceed available cash will have to be provided by external financing. Although the Company has no commitment to provide such financing from any source of funds, other than a $75 million revolving credit agreement and an $80 million revolving credit agreement, described below, the Company expects to be able to satisfy its external financing needs by issuing additional short-term and long-term debt, and by issuing common stock, if necessary. The continued availability of these methods of financing will be dependent upon many factors, including conditions in the securities markets, economic conditions, and the level of the Company's income and cash flow.

On January 13, 1998, the Company issued and sold $100 million principal amount of 6.25% four-year and 11 month Notes. The yield on the Notes, which were issued at a discount, is 6.30%; and the Notes will mature on December 15, 2002. The proceeds from the sale of the Notes were used to repay $100 million principal amount of 7 3/8% Notes, which matured on January 15, 1998.

In March 1998, the Company repurchased $33,798,000 principal amount of 6.20% Notes, at a premium of $178,000, plus accrued interest.

On June 8, 1998, the Company repaid a $50 million Term Loan prior to its August 29, 2000 due date. On June 8, 1998, the Company also repaid $30 million of a $50 million Term Loan prior to its due date of September 6, 2000.

On June 8, 1998, the Company borrowed $80 million under a new revolving credit agreement with a group of banks. The funds were used to repay $80 million of Term Loans prior to their due dates. The borrowing limit of this facility, which extends to June 7, 1999, is $80 million. The facility permits the Company to borrow funds

at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by the Eurodollar interbank market in London. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1998, the Company had $80 million of short-term borrowings outstanding under this facility.

On December 18, 1998, the Company issued and sold $100 million principal amount of 6% five-year Notes. The yield on the Notes, which were issued at a discount, is 6.034%; and the Notes will mature on December 15, 2003. The proceeds from the sale of the Notes were used to repay $66.2 million principal amount of 6.2% Notes, which matured on January 15, 1999, and for general corporate purposes.

On February 1, 1999, the Company converted $7.5 million principal amount Connecticut Development Authority Bonds from a weekly reset mode to a five-year multiannual mode. The interest rate on the Bonds for the five-year period beginning February 1, 1999 is 4.35% and will be paid semi-annually beginning on August 1, 1999. In addition, on February 1, 1999, the Company converted $98.5 million principal amount Business Finance Authority of the State of New Hampshire Bonds from a weekly reset mode to a multiannual mode. The interest rate on $27.5 million principal amount of the Bonds is 4.35% for a three-year period beginning February 1, 1999. The interest rate on $71 million principal amount of the Bonds is 4.55% for a five-year period. Interest on the Bonds will be paid semi-annually beginning on August 1, 1999.

The Company has a revolving credit agreement with a group of banks, which currently extends to December 8, 1999. The borrowing limit of this facility is $75 million. The facility permits the Company to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by either the Eurodollar interbank market in London, or by bidding, at the Company's option. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1998, the Company had no short-term borrowings outstanding under this facility.

In addition, as of December 31, 1998, one of the Company's subsidiaries, American Payment Systems, Inc., had borrowings of $6.8 million outstanding under a bank line of credit agreement.

At December 31, 1998, the Company had $101.4 million of cash and temporary cash investments, an increase of $69.4 million from the balance at December 31, 1997. The components of this increase, which are detailed in the Consolidated Statement of Cash Flows, are summarized as follows:

(In Millions of Dollars)	
Balance, December 31, 1997	$32.0
Net cash provided by operating activities	110.0
Net cash provided by (used in) financing activities:	
Financing activities, excluding dividend payments	29.4
Dividend payments	(40.5)
Net cash provided by investing activities, excluding investment in plant	8.5
Cash invested in plant, including nuclear fuel	(38.0)
Net Change in Cash	69.4
Balance, December 31, 1998	$101.4

The Company's long-term debt instruments do not limit the amount of short-term debt that the Company may issue. The Company's revolving credit agreement described above requires it to maintain an available earnings/interest charges ratio of not less than 1.5:1.0 for each 12-month period ending on the last day of each calendar quarter. For the 12-month period ended December 31, 1998, this coverage ratio was 3.6:1.0.

Subsidiary Operations

UI has one wholly-owned subsidiary, United Resources, Inc. (URI), that serves as the parent corporation for several unregulated businesses, each of which is incorporated separately to participate in business ventures that will complement UI's regulated electric utility business and provide long-term rewards to UI's shareowners.

URI has four wholly-owned subsidiaries. The largest URI subsidiary, American Payment Systems, Inc., manages a national network of agents for the processing of bill payments made by customers of UI and other utilities. It manages agent networks in 36 states and processed approximately $7.5 billion in customer payments during 1998, generating operating revenues of approximately $33.7 million and operating income of approximately $1.7 million. Another subsidiary of URI, Thermal Energies, Inc., owns and operates heating and cooling energy centers in commercial and institutional buildings, and is participating in the development of district heating and cooling facilities in the downtown New Haven area, including the energy center for an office tower and participation as a 52% partner in the energy center for a city hall and office tower complex. A third URI subsidiary, Precision Power, Inc., provides power-related equipment and services to the owners of commercial buildings, government buildings and industrial facilities. URI's fourth subsidiary, United Bridgeport Energy, Inc., is participating in a merchant wholesale electric generating facility being constructed on land leased from UI at its Bridgeport Harbor Station generating plant.

The after-tax impact of the subsidiaries on the consolidated financial statements of the Company is as follows:

	Net Income (loss) (000's)	Earnings per Share	Assets at Dec. 31 (000's)
		(Basic & Diluted)	
1998	$(3,993)	$(0.28)	$33,482
1997	(542)	(0.04)	27,873
1996	(5,237)	(0.37)	36,385

In 1996 and 1998, the Company made provisions for losses of $2.6 million (after-tax) and $2.8 million (after-tax), respectively, associated with collection agent errors and defaults and miscellaneous other items at its American Payment Systems, Inc. subsidiary.

Year 2000 Issue

The Company's planning and operations functions, and its cash flow, are dependent on the timely flow of electronic data to and from its customers, suppliers and other electric utility system managers and operators. In order to assure that this data flow will not be disturbed by the problems emanating from the fact that many existing computer programs were designed without considering the impact of the year 2000 and use only two digits to identify the year in the date field of the programs (the Year 2000 Issue), the Company initiated in mid-1997, and is pursuing, an aggressive program to identify and correct deficiencies in its computer systems. This comprehensive program includes all information technology systems and encompasses systems critical to the generation, transmission and distribution of electric energy as well as traditional business systems. Critical systems have been defined as those business processes, including embedded technology, which if not remediated may have a significant impact on safety, customers, revenue or regulatory compliance. The Company has also identified critical suppliers and other persons with whom data must be exchanged and is asking for assurance of their Year 2000 compliance.

An inventory and assessment of the Company's computer system applications, hardware, software and embedded technologies have been completed, and recommended solutions to all identified risks and exposures have been generated. A testing, remediation, renovation, replacement and retirement program has been in progress since early 1998. Both external and internal resources are being utilized to accomplish the testing, remediation and renovation efforts. A total of 378 affected business processes have been identified and 229 of them have been verified as Year 2000 compliant through testing, remediation, replacement or retirement. The remediation methodology utilized has been Fixed Windowing, and totally independent platforms have been installed for testing all of the applications. Necessary upgrades to mainframe hardware and software are expected to be completed and tested by June 30, 1999. A parallel program for desktop hardware and application software on all platforms is currently projected to be completed and tested, for all critical systems, by June 1, 1999, except in a minority of cases where a business specific need dictates a later date – but not later than December 31, 1999. Requests for documented compliance information have been sent to all critical suppliers, data sharers and facility building owners and, as responses are received, appropriate solutions and testing programs are being developed and executed.

While failure to achieve Year 2000 compliance by any one of a number of critical suppliers and data sharers could have some adverse effect on the success of the Company's implementation program, the Company believes that the entities that might impact the program most significantly in this regard are its telecommunications providers, the other participants in the New England Power Pool (NEPOOL), and the Independent System Operator (ISO) that operates the NEPOOL bulk power supply system. Year 2000 compliance failures by any of these entities could have a material effect on electricity delivery and telemetering. In its efforts to mitigate these risks the Company has taken several actions. UI has communicated its concerns to its principal telecommunications provider and a joint effort to design and plan appropriate testing to insure that all critical telecommunications functions will be operational has commenced. The Year 2000 Issue is also being addressed at the regional level by NEPOOL and the ISO. Coordination efforts with NEPOOL to establish utility testing and readiness are underway. The Company is a participant in all of the subcommittees working within NEPOOL/ISO on efforts to assure operational reliability. The Company is also actively involved with NEPOOL/ISO in the planning effort for integrated contingency planning, as directed by the North American Electric Reliability Council.

Aside from telecommunications and NEPOOL/ISO concerns, the availability of vendor patches, releases and/or replacement equipment or software poses the most significant risk to the success of the Company's Year 2000 compliance implementation program. In order to minimize these risks, the Company will be actively involved in contingency planning. While the Company's knowledge and experience in electric system recovery planning and execution has been demonstrated in the past, the Company recognizes the need for, and importance of, Year 2000-specific contingency planning, because the complex interaction of today's computing and communications systems precludes certainty that all critical system remediation will be successful. At this time, contingency planning for essential business functions is under investigation in most areas, but specific needs have not been fully identified. These plans will be developed by the end of first quarter of 1999, after the majority of business processes are scheduled to be tested and within the timeframe when the NEPOOL/ISO process is due to develop region-wide contingency plans for operations. As a part of the contingency planning process, consideration will be given to potential frequency and duration of interruptions in the generating, financial and communications infrastructures. Since contingency planning is, by nature, a speculative process, there can be no assurance that this planning will completely eliminate the risk of material impacts to the Company's business due to Year 2000 problems. However, the Company recognizes the importance to its customers of a reliable supply of electricity, and it intends to devote whatever resources are necessary to assure that both the program and its implementation are successful.

The Company believes that the successful implementation of this program should ultimately cost no more than $6 million for existing information systems and embedded technology. A total of $2.4 million had been expended as of the end of 1998. As systems testing progresses and more embedded technology vendor product information is forthcoming, business decisions made and testing results verified, the need for increased expenditures, if necessary, will be determined. The Company believes these actions will preclude any adverse impact of the Year 2000 Issue on its operations or financial condition.

C

Results of Operations

1998 vs. 1997 Earnings for the twelve months of 1998 were $42.0 million, or $3.00 per share (both basic and diluted), down $3.6 million, or $.27 per share, from the twelve months of 1997. Excluding one-time items, accelerated amortization due to one-time items and associated regulated "sharing" effects, 1998 earnings from operations were $47.9 million, or $3.42 per share, up $.31 per share from 1997. The one-time items and their earnings per share impacts recorded in these periods are shown at "One-time items recorded in 1997 and 1998" below.

Retail operating revenues increased by about $8.0 million in the twelve months of 1998 compared to 1997. Retail fuel and energy expense increased by $7.2 million and there was an increase of $0.4 million in revenue-based taxes. Overall, retail sales margin (revenue less fuel expense and revenue-based taxes) from operations increased by $0.4 million. The principal components of the retail sales margin change, year over year, include:

(in Millions of Dollars)	
Revenue from:	
DPUC rate order, excluding "sharing"	$(1.3)
Other price changes	(0.3)
Estimate of "real" retail sales growth, up 1.1%	10.8
Estimate of weather effect on retail sales, up 0.2 %	1.8
Sales decrease from Yale University cogeneration, (0.9) %	(3.0)
Fuel and energy, margin effect:	
Sales increase	(2.7)
Increased nuclear availability	0.4
Unscheduled outage at Bridgeport Unit 3 (see Note A)	(2.5)
Fossil price and other	(2.4)

Note A: Saltwater contamination caused a shutdown of the Bridgeport Harbor Unit 3 generating unit on May 22, 1998. The unit returned to full service on August 23, 1998.

Net wholesale margin (wholesale revenue less wholesale energy expense) increased slightly in the twelve months of 1998 compared to the twelve months of 1997. Other operating revenues, which include NEPOOL related transmission revenues, increased by $5.8 million.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $15.0 million in the twelve months of 1998 compared to the twelve months of 1997. The principal components of these expense changes, year over year, include:

(In Millions of Dollars)	
Capacity expense:	
Connecticut Yankee preparing for decommissioning	$(4.2)
Cogeneration and other purchases	(1.3)
Other O&M expense:	
Seabrook	(4.6)
Millstone Unit 3	(4.0)
Fossil generation unit overhauls and outages	7.5
Pension investment performance and assumptions	(3.0)
Personnel reductions	(6.0)
NEPOOL transmission expense	3.1
Other	(2.5)

Depreciation expense, excluding accelerated amortization, increased by $1.5 million in the twelve months of 1998 compared to 1997. According to the Company's current regulatory Rate Plan, "accelerated" amortization of past utility investments is scheduled for every year that the Rate Plan is in effect, contingent upon the Company earning a 10.5% return on utility common stock equity. All of the accelerated amortization in 1997 was recorded in the second quarter of that year as a result of a one-time gain recorded in that quarter. All of the accelerated amortization for 1998, $13.1 million, was recorded against earnings from operations. In addition, as part of the "sharing" mechanism, the Company would have accrued an additional amortization of about $2.6 million ($1.7 million after-tax) in 1998 against utility earnings from operations. Because of the one-time items in 1998, no "sharing" was actually recorded. The one-time charge for property tax expense incurred in the fourth quarter was a utility expense and negated the "sharing" that would have occurred from operations.

Other net income from operations decreased by about $4.7 million in the twelve months of 1998 compared to 1997. The Company's largest unregulated subsidiary, American Payment Systems, Inc. (APS), earned about $1.6 million (before-tax) in 1998, before one-time charges, compared to a breakeven result in 1997. This was more than offset by greater losses, compared to 1997, in the Company's other unregulated subsidiaries: $1.2 million (before-tax) at Precision Power, Inc. from the write-off of previously deferred costs and a review of reserves, and $1.2 million (before-tax) from start-up costs in other unregulated activities. By DPUC order, since consolidation at the unregulated subsidiary level produced no net taxable income in either year, the tax benefits associated with the losses, about $0.8 million in 1998 and $0.4 million in 1997, were treated as benefits to utility income for the purposes of calculating return on utility common equity and "sharing". Other net income also decreased due to the absence of other non-utility income accruals made in 1997, cancelled project write-offs, lower income from non-operating utility investments, and higher unallocated interest charges.

Interest charges, excluding allowance for borrowed funds used during construction, continued on their downward trend, decreasing by $10.4 million in the twelve months of 1998 compared to 1997, as a result of the Company's refinancing program and strong cash flow.

Overview of "Sharing" and the Impact on Earnings

As previously indicated, the Company's regulatory Rate Plan requires a "sharing" of regulated utility income that produces a return on utility equity exceeding 11.5%. The measurement of this utility income and resulting return calculation includes the effects of any utility one-time items. Under the Rate Plan, one-third of the income

above the 11.5% return would be applied to customer bill reductions, one-third would be applied to additional amortization of regulatory assets, and one-third would be retained by shareowners.

Earnings from operations, which excludes the impact of one-time items, should reflect an appropriate imputed amount of "sharing" to reflect accurately what the earnings would have been had neither the one-time items, nor their impact on "sharing", occurred. The Company estimates that the "sharing" that would have occurred had there been no one-time items in 1998 would have been: a revenue reduction of about $3.0 million or $.12 per share, increased amortization of about $1.7 million (after-tax) or $.12 per share, and retention by the Company of $1.7 million of income (after-tax) or $.12 per share. To summarize for 1998:

1998 Earnings Per Share (EPS)	From Operations and "Sharing"	One-time Items and "Sharing" Reversals	Total
Utility earnings before "sharing"	$3.79	$(.45)	$3.34
Less: Utility earnings to be "shared"	(.36)	.36	.00
Utility EPS at 11.5 percent utility return	$3.43	$(.09)	$3.34
Plus: 1/3 Retained "Sharing" benefit	.12	(.12)	.00
Net Utility EPS	3.55	(.21)	3.34
Unregulated Subsidiaries	(.13)	(.21)	(.34)
Total 1998 EPS	$3.42	$(.42)	$3.00
Earnings reported through 3rd quarter	3.02	(.12)	2.90
Imputed 4th quarter earnings	$.40	$(.30)	$.10

One-Time Items Recorded in 1997 and 1998

	One-time Items	EPS
1997 Quarter 2	Cumulative deferred tax benefits associated with future decommissioning of fossil fuel generating plants	$.48
1997 Quarter 2	Accelerated amortization associated with one-time item	$(.30)
1997 Quarter 3	Gain from subleasing office space	$.05
1997 Quarter 4	Pension benefit adjustments associated with 1996 VERP and VSP	$.11
1997 Quarter 4	Contract termination charge	$(.18)
1998 Quarter 2	Subsidiary reserve for agent collection shortfalls and other potentially uncollectible receivables	$(.21)
1998 Quarter 3	Refund of prior period transmission charges, with interest	$.14
	"Sharing" due to one-time items recorded through third quarter	$(.05)
1998 Quarter 4	Property tax settlement with the City of New Haven, CT	$(.59)
	Reversal of "sharing" imputed to property tax settlement	$.29

The most significant one-time item recorded in 1997 was a gain from an income tax expense reduction of $6.7 million in the second quarter, or $.48 per share, which makes provision for the cumulative deferred tax benefits associated with the future decommissioning of fossil fuel generating plants. By order of the DPUC, the Company was instructed to accelerate the amortization of regulatory assets by as much as $6.4 million ($4.1 million after-tax), or $.30 per share, provided that the 1997 return on utility common stock equity would exceed 10.5% for the year. As a result of the tax benefit, the full $6.4 million was charged in the second quarter of 1997.

Additional 1997 one-time items included a $.05 per share gain related to subleasing office space, a gain of $2.5 million ($1.5 million after-tax), or $.11 per share, related to foregone benefits associated with the 1996 voluntary retirement and separation programs, and a charge of $4.3 million ($2.5 million after-tax), or $.18 per share, for terminating a consulting contract.

A one-time charge of $4.9 million ($2.9 million after-tax), or $.21 per share, was recorded in the second quarter of 1998 to address errors in reporting the results of prior years' activity in UI's subsidiary, American Payment Systems, Inc. This is reflected in Other Income and (Deductions), Other-net. See the Company's Form 8-K filing with the SEC, dated June 30, 1998, for a more complete description of this event.

The one-time gain recorded in the third quarter of 1998 was to record a refund of prior period transmission charges. It amounted to $3.4 million or $.14 per share, but was recorded as two separate items; $1.8 million, or a gain of $.07 per share, as a credit to operation expense and $1.6 million, or $.07 per share, of interest income recorded as Other Income and (Deductions), Other-net. At the time this one-time item was recorded, in the third quarter of 1998, the Company estimated that it would be in the Rate Plan "sharing" range of earnings for the year of 1998 in total, and recorded, therefore, a "sharing" revenue reduction and increased amortization expense to reflect that estimate. The "sharing" related to the utility portion of this one-time item, the operation expense credit, was a charge of $.05 per share. The net result of the one-time gain for the period was, therefore, $.09 per share.

The one-time charge recorded in the fourth quarter of 1998 as property tax expense of $14 million, or $.59 per share, reflected the DPUC's rejection of the Company's proposed accounting treatment of a property tax settlement between the Company and the City of New Haven. Upon that rejection, the Company was required to write-off immediately the full effect of that settlement. As a result of this one-time charge, the Company's final 1998 earnings results eliminated the requirement to record any Rate Plan "sharing" in 1998. The one-time charge eliminated "sharing" revenue reductions and increased amortization expense amounting to $.29 per share. The net result of the one-time charge for the period was, therefore, $.30 per share. See Note (L), Commitments and Contingencies - Other Commitments and Contingencies - Property Taxes.

1997 vs. 1996 Earnings for the twelve months of 1997 were $45.6 million, or $3.27 basic earnings per share, up $5.0 million, or $.39 per share, from 1996. Earnings from operations, which exclude one-time items and accelerated amortization of costs attributable to one-time items, decreased by $12.2 million, or $.83 per share, in 1997 compared to 1996. The one-time items recorded in 1996, which amounted to a net loss of $1.06 per share were: charges of $23.0 million ($13.4 million after-tax), or $.95 per share, from early retirement and voluntary severance programs, a charge of $1.4 million ($0.8 million after-tax), or $.06 per share, for the cumulative loss on an office space sublease, a charge of $2.6 million (after-tax), or $.18 per share, related to subsidiary operations, and a gain of $1.8 million (after-tax), or $.13 per share, from the repurchase of preferred stock at a discount to par value.

Retail operating revenues decreased by about $26.3 million in 1997 compared to 1996:

- Results for 1997 reflect an adjustment to retail kilowatt-hour sales and revenue, made in the fourth quarter of 1997, to reverse prior period overestimates of transmission losses. The adjustment added 25 million kilowatt-hours, a 0.5 percent increase compared to 1996 kilowatt-hour sales, and $2.7 million of revenues.

- An additional retail kilowatt-hour sales increase of 0.2% from the prior year increased retail revenues by $1.6 million and sales margin (revenue less fuel expense and revenue-based taxes) by $1.1 million. The Company believes that weather factors had a negative impact on retail kilowatt-hour sales of about 0.5 percent. There was one less day in 1997 (1996 was a leap year), which decreased retail kilowatt-hour sales by 0.3 percent. This would indicate that "real" (i.e. not attributable to abnormal weather or the leap year day in 1996) kilowatt-hour sales increased by about 1.0-1.5 percent for the year.

- Reductions in customer bills, as agreed to by the Company and the DPUC in December 1996, decreased retail revenues by about $23.0 million, including suspension of the fossil fuel adjustment clause (FAC) mechanism that reduced revenues by $6.0 million. This was a somewhat greater decrease than expected, principally because of a decrease in conservation spending and the corresponding decrease in conservation revenues. Other reductions in customer bills, due to rate mix, contract pricing and other pass-through reductions, amounted to $7.6 million.

Wholesale "capacity" revenues increased $2.1 million in 1997 compared to 1996. Wholesale "energy" revenues, which increased during 1997 compared to 1996 as a result of nuclear generating unit outages in the region, are a direct offset to wholesale energy expense and do not contribute to sales margin.

Retail fuel and energy expenses increased by $14.2 million in 1997 compared to 1996. These expenses increased by $12.6 million due to the need for more expensive energy to replace generation by nuclear generating units: for the Connecticut Yankee unit, which ran at nearly full capacity in the first six and one-half months of 1996, for Millstone Unit 3, which ran at nearly full capacity in the first quarter of 1996, for an unplanned eight-day extension of a Seabrook unit refueling outage in the second quarter of 1997 that increased the Company's replacement generation cost by about $0.7 million, and for an unplanned Seabrook unit outage that began on December 5, 1997. The Seabrook unit was returned to service from the last outage on January 17, 1998. Millstone Unit 3 was taken out of service on March 30, 1996 and Connecticut Yankee was taken out of service on July 23, 1996. Retail fuel and energy expenses also increased by about $1.6 million in 1997 compared to 1996, due to higher fossil fuel prices. By order of the DPUC, these costs are not passed on to customers through the FAC.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $1.7 million, excluding the impact of one-time items, in 1997 compared to 1996:

- Purchased capacity expense decreased $6.9 million, due to declining costs from the retired Connecticut Yankee nuclear generating unit, and also due to slightly lower cogeneration costs.

- Operation and maintenance expense increased by $5.1 million. General, refueling and unscheduled outage expenses at the Seabrook nuclear generating unit increased about $2.9 million, and general expenses at the Millstone 3 nuclear generating unit increased $4.8 million. Expenses associated with the Company's re-engineering efforts increased by a net $1.0 million. Other general expenses increased by about $2.9 million. These increases were partly offset by a $4.6 million reduction in pension expense due to investment performance and changes in actuarial assumptions and methodologies, and health benefit reductions of $1.9 million. The increase at Millstone Unit 3 was partly offset by the reversal of a portion of a 1996 provision in "Other income (deductions)."

Depreciation expense, excluding the impact of one-time items, increased by $2.3 million in 1997 compared to 1996. Income taxes, exclusive of the effects of one-time items, changed based on changes in taxable income and tax rates.

Other net income increased by $4.6 million in 1997 compared to 1996 due to an improvement in earnings (reduction in losses) from unregulated subsidiaries. The Company's largest unregulated subsidiary, American Payment Systems, Inc., earned about $101,000 ($47,000 after-tax) in 1997, an improvement of $3.8 million ($2.2 million after-tax) over 1996 losses, excluding one-time items, of about $3.7 million ($2.1 million after-tax). Other UI subsidiaries lost $1.0 million ($0.6 million after-tax) compared to a loss of $0.8 million in 1996. The remainder of the improvement in other net income was due to an increase of $0.8 million in interest income.

Interest charges continued their significant decline, decreasing by $7.5 million, or 11 percent, in 1997 compared to 1996 as a result of the Company's refinancing program and strong cash flow. Also, total preferred dividends (net-of-tax) decreased slightly in 1997 compared to 1996 as a result of purchases of preferred stock by the Company in 1996.

Looking Forward

(The following discussion contains forward-looking statements, which are subject to uncertainties that could cause actual results to differ materially from those currently expected. Readers are cautioned that the Company regards specific numbers as only the "most likely" to occur within a range of possible values.)

FIVE-YEAR RATE PLAN AND RESTRUCTURING LEGISLATION The reader is referred to "Major Influences on Financial Condition," above, for a description of the Company's five-year Rate Plan and Connecticut's electric utility industry restructuring legislation.

1999 EARNINGS 1999 will be a year of transition to the January 1, 2000 effective date of electric utility restructuring legislation passed by the Connecticut legislature in 1998. The Company has taken one major step toward restructuring by proceeding with the sale of its fossil fuel generation plants — referred to as the Generation Asset Divestiture (GAD). That sale is expected to close on or about April 1, 1999.

One result of the generation plant sale will be a reduction in the Company's electric utility rate base, the basis for measuring return on utility common stock equity. Rate base is expected to decline from an average of $1,128 million in 1998 to about $920 million in 1999. Offsetting the decline is the Company's longstanding policy of debt paydown that increases the portion of rate base financed by equity. During 1998, a return of 11.5% on utility common stock equity would have produced earnings of about $3.43 per share. Utility earnings from operations above this range would have given rise to an imputed "sharing" benefit of $.12 per share. Because of the rate base reduction expected in 1999, the allowed return is expected to produce utility earnings in the $3.35-$3.40 per share range. Currently, the Company expects to be in a Rate Plan "sharing" position in 1999, to a somewhat greater extent than was the case for earnings from operations in 1998.

The Company's earnings from its utility business are affected principally by: retail sales that fluctuate with weather conditions and economic activity, nuclear generating unit availability and operating costs, and interest rates. These are all items over which the Company has little control, although the Company engages in economic development activities to increase sales, and hedges its exposure to volatility in interest rates.

The Company's revenues are principally dependent on the level of retail electricity sales. The two primary factors that affect the volume of these retail sales are economic conditions and weather. The Company's retail sales for 1998 of 5,452 gigawatt-hours set an all-time record for the Company and were up 1.4% from the 1997 level.

The Company estimates that mild 1998 weather reduced retail kilowatt-hour sales by about 0.5%, retail revenues by about $3.4 million, and retail sales margin by about $2.7 million. Weather corrected retail sales for 1998 were probably in the 5,470-5,500 gigawatt-hour range. On this weather-adjusted basis, the Company experienced about 1.0-1.5% of "real" sales growth in 1998 over weather-adjusted 1997 sales, with most of the growth appearing to occur in the first three quarters of the year.

Aside from "real" economic growth, reductions in retail electricity sales will occur in 1999 compared to 1998 as a result of the operation of a cogeneration unit at Yale University that produces approximately one half of Yale's annual electricity requirements (about 1.5% of the Company's total 1998 retail sales). This unit commenced operations in mid-1998, and has reduced total Company retail kilowatt-hour sales by about 0.9% in 1998 compared to 1997. The remaining impact will be reflected in the first half of 1999. Thus, it would require "real" growth of 0.5 percent in 1999 compared to 1998 just to maintain the 1998 level of "real" sales. Retail kilowatt-hour sales growth of 1.0% produces a margin improvement of about $5.0 million, before any "sharing" effect considerations.

Prices in individual customer rate classes will not change in 1999 relative to 1998, exclusive of any "sharing." However, sales growth is occurring in rate classes with higher-than-average prices, and the Company expects to have an increase in retail revenue of about $3.0 million in 1999 compared to 1998 from this price mix improvement.

Other operating revenues are expected to increase as a result of NEPOOL related transmission revenues by about $4.0 million due to NEPOOL restructuring changes; but this would have no net income effect as the higher revenues are due to higher transmission operating expense. Other than the NEPOOL impact, these revenues are expected to decrease by about $2 million to a more normal level. The Company does not anticipate, at this time, any other significant revenue reductions in 1999 retail revenues compared to 1998, unless the Company is achieving a "sharing" level of earnings.

As a result of GAD, wholesale capacity revenues will decrease by about $7.7 million in 1999 compared to 1998, because existing wholesale sales contracts were part of the asset sale. Also as a result of GAD, the Company's fuel and purchased energy charges will increase in 1999 compared to 1998 by about $40 million, to replace the power previously provided by the Company's fossil-fueled generation plants. This power supply purchase agreement was part of the GAD plant sale and it will help to ensure adequate resources to meet customer energy demands under a short-term fixed price agreement until July 2000 (the price declines somewhat in 2000 compared to 1999) when all customers will have a choice of generation suppliers. The Company expects that its projected 1999 energy requirements that are not met by the GAD power supply purchase agreement will be met at lower prices than those experienced in 1998, primarily because of lower projected fossil fuel prices and energy prices in general. This is expected to result in energy cost savings of about $5 million.

Purchased capacity costs should decrease by about $2 million in 1999, due primarily to the retirement of the Connecticut Yankee nuclear generation plant.

Several other expense categories are expected to be reduced substantially in 1999 because of GAD and the Company's other cost reduction efforts, offsetting the impact of the increase in purchased energy. Operation and maintenance expense is projected to decrease by a net $22 million, reflecting a decrease of $32 million due to GAD and other general changes, partly offset by increases of about $5 million for nuclear unit refueling outages, $1 million for Y2K costs and $4 million due to NEPOOL transmission charges. The latter would have no net income effect, as the higher transmission expense would be covered by higher transmission revenues. Total Y2K costs for 1999 are currently projected at about $3.6 million. Other operation and maintenance expenses in 1999 should be fairly stable compared to 1998, unless an event occurs that cannot be predicted at this time.

Interest costs are expected to decline by about $14 million in 1999 compared to 1998, to about $38 million, a level that was last experienced in 1982. This anticipated interest cost reduction will result largely from debt paydown through use of the after-tax cash proceeds from GAD. The Company also expects to generate substantial cash flow from operations after dividend and capital spending, that will also be used to pay down debt.

Depreciation, excluding accelerated amortization, should decrease by about $13 million in 1999 compared to 1998, due mostly to GAD but also from the near completion in 1998 of amortization of previously capitalized conservation program expenditures. A significant portion of the decrease in depreciation related to GAD will not affect taxable income and will not increase income taxes, and will therefore supplement the $13 million decrease with an additional tax benefit, comparing 1999 to 1998, of about $2.5 million, or $.18 per share.

Accelerated amortization, per the Rate Plan, will increase by about $7 million in 1999 compared to 1998. Property taxes should decrease by about $2 million, due mostly to GAD. Other operating expenses can be expected to have some increases and some decreases that should, more or less, offset one another.

In summary, the Company expects substantial net expense reductions as a result of GAD and ongoing cost control measures that should more than compensate for increased charges for purchased power and increased accelerated amortization costs in 1999. Such performance should allow utility earnings to increase above an 11.5% return on common stock equity into the Rate Plan "sharing" range. The 11.5% return level would produce utility earnings from operations of about $3.35-$3.40 per share, while the "shared" earnings benefit is currently anticipated to contribute about $.20 per share, although the size of this benefit will fluctuate with every event that affects utility operations during the year. The Company expects that 1999 quarterly earnings from operations will follow a pattern similar to that of 1998 on a weather-normalized basis.

Unregulated subsidiaries are expected to experience a loss of up to $.10 per share to earnings in 1999. American Payment Systems, Inc. is expected to build on 1998's contribution to earnings from operations of $.07 per share. However, this will depend on its ability to expand sales to its utility customers. Precision Power, Inc. (PPI) increased its organizational infrastructure in 1998, also in an effort to increase its presence in its principal markets of distributed power systems and services. At its current level of expense, PPI would lose $.10 to $.15 per share in 1999 if no substantial new contracts are obtained. PPI may also engage in acquisition activities in 1999 that may have short-term dilutive effects on earnings beyond those indicated above.

As a result of the earnings contributions anticipated from all of its different business activities described above, the Company expects earnings per share from operations to be in the range of $3.45 to $3.65 in 1999. These estimates are subject to all of the contingencies and uncertainties detailed in the preceding discussion and the reader is cautioned to read the "Looking Forward" and "Major Influences on Financial Condition" sections in their entirety.

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and the Shareholders of The United Illuminating Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income of retained earnings and of cash flows present fairly, in all material respects, the financial position of The United Illuminating Company and its subsidiaries (the"Company") at December 31, 1998, 1997, and 1996 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with generally accepted auditing standards, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

February 12, 1999

The United Illuminating Company
Consolidated Statement of Income

For the Years Ended December 31, 1998, 1997 & 1996

(In Thousands of Dollars except per share amount)	1998	1997	1996
OPERATING REVENUES (NOTE G)	$686,191	$710,267	$726,020
OPERATING EXPENSES			
Operation			
Fuel and energy	151,544	182,666	160,517
Capacity purchased	34,515	39,976	46,830
Early retirement program charges	-	-	23,033
Other	146,058	158,600	158,945
Maintenance	42,888	42,203	37,652
Depreciation (Note G)	82,809	74,618	65,921
Amortization of cancelled nuclear project and deferred return (Note D and J)	13,758	13,758	13,758
Income taxes (Note A and F)	53,619	41,333	53,090
Other taxes (Note G)	64,674	52,540	57,139
TOTAL	589,865	605,694	616,885
OPERATING INCOME	96,326	104,573	109,135
OTHER INCOME AND (DEDUCTIONS)			
Allowance for equity funds used during construction	13	336	940
Other-net (Note G)	(3,803)	4,186	(7,166)
Non-operating income taxes	5,866	2,496	9,332
TOTAL	2,076	7,018	3,106
INCOME BEFORE INTEREST CHARGES	98,402	111,591	112,241
INTEREST CHARGES			
Interest on long-term debt	50,129	63,063	66,305
Interest on Seabrook obligation bonds owned by the company	(7,293)	(6,905)	(1,259)
Other interest (Note G)	6,507	3,280	2,092
Allowance for borrowed funds used during construction	(455)	(1,239)	(1,435)
	48,888	58,199	65,703
Amortization of debt expense and redemption premiums	2,511	2,788	2,629
NET INTEREST CHARGES	51,399	60,987	68,332
MINORITY INTEREST IN PREFERRED SECURITIES	4,813	4,813	4,813
NET INCOME	42,190	45,791	39,096
Discount on preferred stock redemptions	(21)	(48)	(1,840)
Dividends on preferred stock	201	205	330
INCOME APPLICABLE TO COMMON STOCK	$42,010	$45,634	$40,606
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - BASIC	14,018	13,976	14,101
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - DILUTED	14,023	13,992	14,131
EARNINGS PER SHARE OF COMMON STOCK - BASIC	$3.00	$3.27	$2.88
EARNINGS PER SHARE OF COMMON STOCK - DILUTED	$3.00	$3.26	$2.87
CASH DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$2.88	$2.88	$2.88

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

The United Illuminating Company
Consolidated Statement of Cash Flows

For the Years Ended December 31, 1998, 1997 & 1996

(In Thousands of Dollars)	1998	1997	1996
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$42,190	$45,791	$39,096
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	88,099	79,487	70,363
Deferred income taxes	1,056	7,986	(2,276)
Deferred investment tax credits - net	(762)	(762)	(762)
Amortization of nuclear fuel	6,892	5,799	5,690
Allowance for funds used during construction	(468)	(1,575)	(2,375)
Amortization of deferred return	12,586	12,586	12,586
Early retirement costs accrued	-	-	23,033
Changes in:			
Accounts receivable - net	(6,505)	16,944	(23,555)
Fuel, materials and supplies	(14,466)	2,863	239
Prepayments	(4,027)	211	(557)
Accounts payable	(15,259)	641	22,657
Interest accrued	(63)	(3,569)	(671)
Taxes accrued	4,849	3,663	(4,794)
Other assets and liabilities	(4,062)	(1,644)	6,078
Total Adjustments	67,870	122,630	105,656
NET CASH PROVIDED BY OPERATING ACTIVITIES	110,060	168,421	144,752
CASH FLOWS FROM FINANCING ACTIVITIES			
Common stock	4,923	(6,432)	40
Long-term debt	199,636	98,500	82,500
Notes payable	49,141	26,786	10,965
Securities redeemed and retired:			
Preferred stock	(52)	(110)	(6,078)
Long-term debt	(222,348)	(151,199)	(72,895)
Discount on preferred stock redemption	21	48	1,840
Expenses of issues	(1,600)	(1,500)	(442)
Lease obligations	(339)	(315)	(291)
Dividends			
Preferred stock	(202)	(206)	(410)
Common stock	(40,285)	(40,408)	(40,399)
NET CASH USED IN FINANCING ACTIVITIES	(11,105)	(74,836)	(25,170)
CASH FLOWS FROM INVESTING ACTIVITIES			
Plant expenditures, including nuclear fuel	(38,040)	(33,436)	(47,174)
Investment in Seabrook obligation bonds	8,528	(34,541)	(71,084)
NET CASH USED IN INVESTING ACTIVITIES	(29,512)	(67,977)	(118,258)
CASH AND TEMPORARY CASH INVESTMENTS:			
NET CHANGE FOR THE PERIOD	69,443	25,608	1,324
BALANCE AT BEGINNING OF PERIOD	32,002	6,394	5,070
BALANCE AT END OF PERIOD	$101,445	$32,002	$6,394
CASH PAID DURING THE PERIOD FOR:			
Interest (net of amount capitalized)	$51,481	$59,441	$69,669
Income taxes	$42,450	$26,773	$51,415

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

The United Illuminating Company
Consolidated Balance Sheet

December 31, 1998, 1997 & 1996

ASSETS

(In Thousands of Dollars)	1998	1997	1996
UTILITY PLANT AT ORIGINAL COST			
In service	$1,886,930	$1,867,145	$1,843,952
Less, accumulated provision for depreciation	714,375	644,971	585,646
	1,172,555	1,222,174	1,258,306
Construction work in progress	33,695	25,448	40,998
Nuclear fuel	20,174	25,990	23,010
NET UTILITY PLANT	1,226,424	1,273,612	1,322,314
OTHER PROPERTY AND INVESTMENTS	37,873	32,451	26,081
CURRENT ASSETS			
Cash and temporary cash investments	101,445	32,002	6,394
Accounts receivable			
Customers, less allowance for doubtful accounts of $1,800, $1,800 and $2,300	54,178	57,231	63,722
Other	37,472	27,914	38,367
Accrued utility revenues	21,079	25,269	29,139
Fuel, materials and supplies, at average cost	33,613	19,147	22,010
Prepayments	7,424	3,397	3,608
Other	154	67	110
TOTAL	255,365	165,027	163,350
DEFERRED CHARGES			
Unamortized debt issuance expenses	9,421	6,611	6,580
Other	1,664	5,727	1,485
TOTAL	11,085	12,338	8,065
REGULATORY ASSETS (future amounts due from customers through the ratemaking process)			
Income taxes due principally to book-tax differences (Note A)	264,811	277,350	289,672
Connecticut Yankee	42,633	51,313	64,851
Deferred return - Seabrook Unit 1	12,586	25,171	37,757
Unamortized redemption costs	23,468	23,027	25,063
Unamortized cancelled nuclear project	10,952	12,125	13,297
Uranium enrichment decommissioning costs	1,177	1,312	1,377
Other	4,962	6,357	9,068
TOTAL	360,589	396,655	441,085
	$1,891,336	$1,880,083	$1,960,895

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

The United Illuminating Company
Consolidated Balance Sheet

December 31, 1998, 1997 & 1996

CAPITALIZATION & LIABILITIES

(In Thousands of Dollars)	1998	1997	1996
CAPITALIZATION (Note B)			
Common stock equity			
Common stock	$292,006	$288,730	$284,579
Paid-in capital	2,046	1,349	772
Capital stock expense	(2,182)	(2,182)	(2,182)
Unearned employee stock ownership plan equity	(10,210)	(11,160)	-
Retained earnings	163,847	162,226	156,847
	445,507	438,963	440,016
Preferred stock	4,299	4,351	4,461
Minority interest in preferred securities	50,000	50,000	50,000
Long-term debt			
Long-term debt	757,370	746,058	826,527
Investment in Seabrook obligation bonds	(92,860)	(101,388)	(66,847)
Net long-term debt	664,510	644,670	759,680
TOTAL	1,164,316	1,137,984	1,254,157
NON-CURRENT LIABILITIES			
Connecticut Yankee contract obligation	32,711	40,821	54,752
Pensions accrued (Note H)	31,097	39,149	49,205
Nuclear decommissioning obligation	23,045	17,538	12,851
Obligations under capital leases	16,506	16,853	17,193
Other	6,622	5,507	4,815
TOTAL	109,981	119,868	138,816
CURRENT LIABILITIES			
Current portion of long-term debt	66,202	100,000	69,900
Notes payable	86,892	37,751	10,965
Accounts payable	53,440	68,699	68,058
Dividends payable	10,155	10,051	10,205
Taxes accrued	9,015	4,166	503
Interest accrued	10,203	10,266	13,835
Obligations under capital leases	348	340	315
Other accrued liabilities	39,845	37,471	36,091
TOTAL	276,100	268,744	209,872
CUSTOMERS' ADVANCES FOR CONSTRUCTION	1,867	1,878	1,888
REGULATORY LIABILITIES (future amounts owed to customers through the ratemaking process)			
Accumulated deferred investment tax credits	15,623	16,385	17,147
Other	2,065	2,356	1,811
TOTAL	17,688	18,741	18,958
DEFERRED INCOME TAXES (future tax liabilities owed to taxing authorities)	321,384	332,868	337,204
COMMITMENTS AND CONTINGENCIES (Note L)			
	$1,891,336	$1,880,083	$1,960,895

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

C

The United Illuminating Company
Consolidated Statement of Retained Earnings

For the Years Ended December 31, 1998, 1997 & 1996

(In Thousands of Dollars)	1998	1997	1996
BALANCE, JANUARY 1	$162,226	$156,847	$156,877
Net income	42,190	45,791	39,096
Adjustments associated with repurchase of preferred stock	21	48	1,815
TOTAL	204,437	202,686	197,788
DEDUCT CASH DIVIDENDS DECLARED			
Preferred stock	201	205	330
Common stock	40,389	40,255	40,611
TOTAL	40,590	40,460	40,941
BALANCE, DECEMBER 31	$163,847	$162,226	$156,847

The accompanying Notes to Consolidated Financial Statements are an integral part of the financial statements.

The United Illuminating Company (UI or the Company) is an operating electric public utility company, engaged principally in the production, purchase, transmission, distribution and sale of electricity for residential, commercial and industrial purposes in a service area of about 335 square miles in the southwestern part of the State of Connecticut. The service area, largely urban and suburban in character, includes the principal cities of Bridgeport (population 137,000) and New Haven (population 124,000) and their surrounding areas. Situated in the service area are retail trade and service centers, as well as large and small industries producing a wide variety of products, including helicopters and other transportation equipment, electrical equipment, chemicals and pharmaceuticals.

In addition, the Company has created and owns unregulated subsidiaries. The Board of Directors of the Company has authorized the investment of a maximum of $32.25 million in the unregulated subsidiaries, and, at February 28, 1999, $30 million had been invested. A wholly-owned subsidiary, United Resources, Inc., serves as the parent corporation to American Payment Systems, Inc., (APS) which manages a national network of agents for the processing of bill payments made by customers of other utilities.

(A) Statement of Accounting Policies

ACCOUNTING RECORDS The accounting records are maintained in accordance with the uniform systems of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the Connecticut Department of Public Utility Control (DPUC).

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

PRINCIPLES OF CONSOLIDATION The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary, United Resources, Inc. Intercompany accounts and transactions have been eliminated in consolidation.

REGULATORY ACCOUNTING The consolidated financial statements of the Company are in conformity with generally accepted accounting principles and with accounting for regulated electric utilities prescribed by the Federal Energy Regulatory Commission (FERC) and the Connecticut Department of Public Utility Control (DPUC). Generally accepted accounting principles for regulated entities allow the Company to give accounting recognition to the actions of regulatory authorities in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation". In accordance with SFAS No. 71, the Company has deferred recognition of costs (a regulatory asset) or has recognized obligations (a regulatory liability) if it is probable that such costs will be recovered or obligations relieved in the future through the ratemaking process. In addition to the Regulatory Assets and Liabilities separately identified on the Consolidated Balance Sheet, there are other regulatory assets and liabilities, such as conservation and load management costs and certain deferred tax liabilities. The Company also has obligations under long-term power contracts, the recovery of which is subject to regulation.

The effects of competition could cause the operations of the Company, or a portion of its assets or operations, to cease meeting the criteria for application of these accounting rules. The Company expects to con-

tinue to meet these criteria in the forseeable future. The Restructuring Act enacted in Connecticut in 1998 provides for the Company to recover in future regulated service rates previously deferred costs through ongoing assessments to be included in such rates. If the Company, or a portion of its assets or operations, were to cease meeting these criteria, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met. If this change in accounting were to occur, it could have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well. See Note (C), Rate-Related Regulatory Proceedings.

C

RECLASSIFICATION OF PREVIOUSLY REPORTED AMOUNTS Certain amounts previously reported have been reclassified to conform with current year presentations.

UTILITY PLANT The cost of additions to utility plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The cost of current repairs and minor replacements is charged to appropriate operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation.

The Company's utility plant in service as of December 31, 1998, 1997 and 1996 was comprised as follows:

(In Thousands of Dollars)	1998	1997	1996
Production	$1,133,984	$1,131,285	$1,124,113
Transmission	161,643	161,288	160,970
Distribution	408,845	401,426	387,825
General	56,264	52,776	47,889
Future use plant	30,505	30,594	32,751
Other	95,689	89,776	90,404
	$1,886,930	$1,867,145	$1,843,952

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION In accordance with the applicable regulatory systems of accounts, the Company capitalizes AFUDC, which represents the approximate cost of debt and equity capital devoted to plant under construction. In accordance with FERC prescribed accounting, the portion of the allowance applicable to borrowed funds is presented in the Consolidated Statement of Income as a reduction of interest charges, while the portion of the allowance applicable to equity funds is presented as other income. Although the allowance does not represent current cash income, it has historically been recoverable under the ratemaking process over the service lives of the related properties. The Company compounds the allowance applicable to major construction projects semi-annually. Weighted average AFUDC rates in effect for 1998, 1997 and 1996 were 7.0%, 7.5% and 9.0%, respectively.

DEPRECIATION Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives determined by independent engineers. One-half year's depreciation is taken in the year of addition and disposition of utility plant, except in the case of major operating units on which depreciation commences in the month they are placed in service and ceases in the month they are removed from service. The aggregate annual provisions for depreciation for the years 1998, 1997 and 1996 were equivalent to approximately 3.26%, 3.15% and 3.12%, respectively, of the original cost of depreciable property.

INCOME TAXES In accordance with Statement of Financial Accounting Standards (SFAS) No. 109 "Accounting for Income Taxes", the Company has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, the Company has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences.

For ratemaking purposes, the Company normalizes all investment tax credits (ITC) related to recoverable plant investments except for the ITC related to Seabrook Unit 1, which was taken into income in accordance with provisions of a 1990 DPUC retail rate decision.

ACCRUED UTILITY REVENUES The estimated amount of utility revenues (less related expenses and applicable taxes) for service rendered, but not billed, is accrued at the end of each accounting period.

CASH AND TEMPORARY CASH INVESTMENTS For cash flow purposes, the Company considers all highly liquid debt instruments with a maturity of three months or less at the date of purchase to be cash and temporary cash investments. The Company records outstanding checks as accounts payable until the checks have been honored by the banks.

The Company is required to maintain an operating deposit with the project disbursing agent related to its 17.5% ownership interest in Seabrook Unit 1. This operating deposit, which is the equivalent to one and one half months of the funding requirement for operating expenses, is restricted for use and amounted to $3.8 million, $2.3 million and $3.4 million, at December 31, 1998, 1997 and 1996, respectively.

INVESTMENTS The Company's investment in the Connecticut Yankee Atomic Power Company, a nuclear generating company in which the Company has a 9½% stock interest, is accounted for on an equity basis. This investment amounted to $9.9 million, $10.5 million and $10.1 million at December 31, 1998, 1997 and 1996, respectively, and is included on the Consolidated Balance Sheet as a regulatory asset. See Note (L), Commitments and Contingencies - Other Commitments and Contingencies - Connecticut Yankee.

FOSSIL FUEL COSTS Historically, the amount of fossil fuel costs that cannot be reflected currently in customers' bills pursuant to the fossil fuel adjustment clause in the Company's rates has been deferred at the end of each accounting period. Since adoption of the deferred accounting procedure in 1974, rate decisions by the DPUC and its predecessors have consistently made specific provision for amortization and ratemaking treatment of the Company's existing deferred fossil fuel cost balances. As a result of a December 1996 DPUC decision, the Company has suspended this deferred accounting procedure unless the average fossil fuel oil prices increase or decrease outside a certain bandwidth prescribed in the decision.

INTEREST RATE AND FUEL PRICE MANAGEMENT The Company utilizes interest rate and fuel oil price management instruments to manage interest rate and fuel oil price risk. Interest rate swap agreements have been entered into that effectively convert the interest rates on $225 million of variable rate borrowings to fixed rate borrowings. Amounts receivable or payable under these swap agreements are accrued and charged to interest expense. The Company enters into basic fuel oil price management instruments to help minimize fuel oil price risk by fixing the future price for fuel oil used for generation. Amounts receivable or payable under these instruments are recognized in income when realized.

RESEARCH AND DEVELOPMENT COSTS Research and development costs, including environmental studies, are capitalized if related to specific construction projects and depreciated over the lives of the related assets. Other research and development costs are charged to expense as incurred.

C

PENSION AND OTHER POSTEMPLOYMENT BENEFITS The Company accounts for normal pension plan costs in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions", and for supplemental retirement plan costs and supplemental early retirement plan costs in accordance with the provisions of SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits".

The Company accounts for other postemployment benefits, consisting principally of health and life insurance, under the provisions of SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", which requires, among other things, that the liability for such benefits be accrued over the employment period that encompasses eligibility to receive such benefits. The annual incremental cost of this accrual has been allowed in retail rates in accordance with a 1992 rate decision of the DPUC.

URANIUM ENRICHMENT OBLIGATION Under the Energy Policy Act of 1992 (Energy Act), the Company will be assessed for its proportionate share of the costs of the decontamination and decommissioning of uranium enrichment facilities operated by the Department of Energy. The Energy Act imposes an overall cap of $2.25 billion on the obligation assessed to the nuclear utility industry and limits the annual assessment to $150 million each year over a 15-year period. At December 31, 1998, the Company's unfunded share of the obligation, based on its ownership interest in Seabrook Unit 1 and Millstone Unit 3, was approximately $1.1 million. Effective January 1, 1993, the Company was allowed to recover these assessments in rates as a component of fuel expense. Accordingly, the Company has recognized these costs as a regulatory asset on its Consolidated Balance Sheet.

NUCLEAR DECOMMISSIONING TRUSTS External trust funds are maintained to fund the estimated future decommissioning costs of the nuclear generating units in which the Company has an ownership interest. These costs are accrued as a charge to depreciation expense over the estimated service lives of the units and are recovered in rates on a current basis. The Company paid $2,580,000, $2,571,000 and $2,130,000 during 1998, 1997 and 1996 into the decommissioning trust funds for Seabrook Unit 1 and Millstone Unit 3. At December 31, 1998, the Company's shares of the trust fund balances, which included accumulated earnings on the funds, were $16.5 million and $6.5 million for Seabrook Unit 1 and Millstone Unit 3, respectively. These fund balances are included in "Other Property and Investments" and the accrued decommissioning obligation is included in "Non-current Liabilities" on the Company's Consolidated Balance Sheet.

IMPAIRMENT OF LONG-LIVED ASSETS Statement of Financial Accounting Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets to Be Disposed Of" requires the recognition of impairment losses on long-lived assets when the book value of an asset exceeds the sum of the expected future undiscounted cash flows that result from the use of the asset and its eventual disposition. This standard also requires that rate-regulated companies recognize an impairment loss when a regulator excludes all or part of a cost from rates, even if the regulator allows the company to earn a return on the remaining allowable costs. Under this standard, the probability of recovery and the recognition of regulatory assets under the criteria of SFAS No. 71 must be assessed on an ongoing basis. The Company does not have any assets that are impaired under this standard.

APS REVENUES AND AGENT COLLECTIONS APS recognized revenue of $33.7 million, $31.7 million and $19.2 million for the years 1998, 1997 and 1996, respectively, based on established fees per payment transaction processed. Cash associated with customer payments are the property of other utilities and have not been reflected in UI's consolidated financial statements.

EARNINGS PER SHARE The following table presents a reconciliation of the numerators and denominators of the basic and diluted earnings per share calculations for the years 1998, 1997 and 1996:

(In Thousands of Dollars Except Per Share Amounts)	Income Applicable to Common Stock (Numerator)	Average Number of Shares Outstanding (Denominator)	Earnings per Share
1998			
Basic earnings per share	$42,010	14,018	$3.00
Effect of dilutive stock options	-	5	(.00)
Diluted earnings per share	$42,010	14,023	$3.00
1997			
Basic earnings per share	$45,634	13,976	$3.27
Effect of dilutive stock options	-	16	(.01)
Diluted earnings per share	$45,634	13,992	$3.26
1996			
Basic earnings per share	$40,606	14,101	$2.88
Effect of dilutive stock options	-	30	(.01)
Diluted earnings per share	$40,606	14,131	$2.87

STOCK-BASED COMPENSATION The Company accounts for employee stock-based compensation in accordance with Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation". This statement establishes financial accounting and reporting standards for stock-based employee compensation plans, such as stock purchase plans, stock options, restricted stock, and stock appreciation rights. The statement defines the methods of determining the fair value of stock-based compensation and requires the recognition of compensation expense for book purposes. However, the statement allows entities to continue to measure compensation expense in accordance with the prior authoritative literature, APB No. 25, "Accounting for Stock Issued to Employees", but requires that pro forma net income and earnings per share be disclosed for each year for which an income statement is presented as if SFAS No. 123 had been applied. The accounting requirements of this statement are effective for transactions entered into after 1995. However, pro forma disclosures must include the effects of all awards granted after January 1, 1995. As of December 31, 1998, there were no options granted to which this statement would apply. The Company has not elected to adopt the expense recognition provisions of SFAS No. 123.

NEW ACCOUNTING STANDARDS In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". This statement, which is effective for fiscal quarters of fiscal years beginning after June 15, 1999, establishes accounting and reporting standards for derivative instruments and for hedging activities. It requires entities to recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value. The accounting for the changes in the fair value of a derivative (gains and losses) would depend on the intended use and designation of the derivative. The Company currently does not anticipate utilizing derivative instruments of the type defined in this statement, on or after the effective date of this statement.

(B) Capitalization

	December 31, 1998		1997		1996	
	Shares Outstanding	$(000's)	Shares Outstanding	$(000's)	Shares Outstanding	$(000's)
COMMON STOCK EQUITY						
Common stock, no par value, at December 31 (a)	14,034,562	$292,006	13,907,824	$288,730	14,101,291	$284,579
Shares authorized						
1996 30,000,000						
1997 30,000,000						
1998 30,000,000						
Paid-in capital		2,046		1,349		772
Capital stock expense		(2,182)		(2,182)		(2,182)
Unearned employee stock ownership plan equity		(10,210)		(11,160)		-
Retained earnings (b)		163,847		162,226		156,847
TOTAL COMMON STOCK EQUITY		445,507		438,963		440,016
PREFERRED AND PREFERENCE STOCK (c)						
Cumulative preferred stock, $100 par value, shares authorized at December 31,						
1996 1,119,612						
1997 1,119,612						
1998 1,119,612						
Preferred stock issues:						
4.35% Series A	10,370		10,894		11,297	
4.72% Series B	17,158		17,158		17,658	
4.64% Series C	12,745		12,745		12,945	
5 5/8% Series D	2,712		2,712		2,712	
	42,985	4,299	43,509	4,351	44,612	4,461
Cumulative preferred stock, $25 par value: 2,400,000 shares authorized						
Preferred stock issues	-	-	-	-	-	-
Cumulative preference stock, $25 par value: 5,000,000 shares authorized						
Preference stock issues		-	-	-	-	-
TOTAL PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION		4,299		4,351		4,461
MINORITY INTEREST IN PREFERRED SECURITIES (D)		50,000		50,000		50,000

(B) Capitalization (cont'd)

(In Thousands of Dollars)	1998	December 31, 1997	1996
LONG-TERM DEBT (E)			
First Mortgage Bonds:			
9.44%, Series B	-	-	$32,400
OTHER LONG-TERM DEBT			
Pollution Control Revenue Bonds:			
Variable rate, 1996 Series, due June 26, 2026	7,500	7,500	7,500
9 3/8%, 1987 Series, due July 1, 2012	-	-	25,000
10 3/4%, 1987 Series, due November 1, 2012	-	-	43,500
8%, 1989 Series A, due December 1, 2014	25,000	25,000	25,000
5 7/8%, 1993 Series, due October 1, 2033	64,460	64,460	64,460
Solid Waste Disposal Revenue Bonds:			
Adjustable rate 1990 Series A, due September 1, 2015	-	-	30,000
Pollution Control Refunding Revenue Bonds:			
Variable rate, 1997 Series, due July 30, 2027	98,500	98,500	-
Notes:			
7 3/8%, 1992 Series G, due January 15, 1998	-	100,000	100,000
6.20%, 1993 Series H, due January 15, 1999	66,202	100,000	100,000
6.25%, 1998 Series I, due December 15, 2002	100,000	-	-
6.00%, 1998 Series J, due December 15, 2003	100,000	-	-
Term Loans:			
6.95%, due August 29, 2000	50,000	50,000	50,000
6.47%, due September 6, 2000	-	50,000	50,000
6.4375%, due September 6, 2000	20,000	50,000	50,000
6.675%, due October 25, 2001	25,000	25,000	25,000
7.005%, due October 25, 2001	50,000	50,000	50,000
Obligation under the Seabrook Unit 1 sale/leaseback agreement	217,230	225,601	243,660
	823,892	846,061	896,520
Unamortized debt discount less premium	(320)	(3)	(93)
TOTAL LONG-TERM DEBT	823,572	846,058	896,427
LESS			
Current portion included in Current Liabilities (e)	66,202	100,000	69,900
Investment-Seabrook Lease Obligation Bonds	92,860	101,388	66,847
TOTAL LONG-TERM DEBT INCLUDED IN CAPITALIZATION	664,510	644,670	759,680
TOTAL CAPITALIZATION	$1,164,316	$1,137,984	$1,254,157

(A) COMMON STOCK The Company had 14,334,922 shares of its common stock, no par value, outstanding at December 31, 1998, of which 300,360 shares were unallocated shares held by the Company's Employee Stock Ownership Plan ("ESOP") and not recognized as outstanding for accounting purposes.

The Company issued 98,798 shares of common stock in 1998, 134,833 shares of common stock in 1997 and 1,200 shares of common stock in 1996, pursuant to a stock option plan.

In 1990, the Company's Board of Directors and the shareowners approved a stock option plan for officers and key employees of the Company. The plan provides for the awarding of options to purchase up to 750,000 shares of the Company's common stock over periods of from one to ten years following the dates when the options are granted. The Connecticut Department of Public Utility Control (DPUC) has approved the issuance of 500,000 shares of stock pursuant to this plan. The exercise price of each option cannot be less than the market value of the stock on the date of the grant. Options to purchase 3,500 shares of stock at an exercise price of $30 per share, 7,800 shares of stock at an exercise price of $39.5625 per share, and 5,000 shares of stock at an exercise price of $42.375 per share have been granted by the Board of Directors and remained outstanding at December 31, 1998. Options to purchase 14,299 shares of stock at an exercise price of $30 per share, 54,500 shares of stock at an exercise price of $30.75 per share, 4,000 shares of stock at an exercise price of $35.625 per share, and 25,999 shares of stock at an exercise price of $39.5625 per share were exercised during 1998.

The Company has entered into an arrangement under which it loaned $11.5 million to The United Illuminating Company ESOP. The trustee for the ESOP used the funds to purchase shares of the Company's common stock in open market transactions. The shares will be allocated to employees' ESOP accounts, as the loan is repaid, to cover a portion of the Company's required ESOP contributions. The loan will be repaid by the ESOP over a 12-year period, using the Company contributions and dividends paid on the unallocated shares of the stock held by the ESOP. As of December 31, 1998 and 1997, 300,360 shares and 328,300 shares, with a fair market value of $15.5 million and $15.1 million, respectively, had been purchased by the ESOP and had not been committed to be released or allocated to ESOP participants.

(B) RETAINED EARNINGS RESTRICTION The indenture under which $266.2 million principal amount of Notes are issued places limitations on the payment of cash dividends on common stock and on the purchase or redemption of common stock. Retained earnings in the amount of $105.7 million were free from such limitations at December 31, 1998.

(C) PREFERRED AND PREFERENCE STOCK The par value of each of these issues was credited to the appropriate stock account and expenses related to these issues were charged to capital stock expense.

In April 1998, the Company purchased at a discount on the open market, and canceled, 524 shares of its $100 par value 4.35%, Series A preferred stock. The shares, having a par value of $52,400 were purchased for $31,440, creating a net gain of $20,960.

Shares of preferred stock have preferential dividend and liquidation rights over shares of common stock. Preferred shareholders are not entitled to general voting rights. However, if any preferred dividends are in arrears for six or more quarters, or if certain other events of default occur, preferred shareholders are entitled to elect a majority of the Board of Directors until all preferred dividend arrearages are paid and any event of default is terminated.

Preference stock is a form of stock that is junior to preferred stock but senior to common stock. It is not subject to the earnings coverage requirements or minimum capital and surplus requirements governing the issuance of preferred stock. There were no shares of preference stock outstanding at December 31, 1998.

(D) PREFERRED CAPITAL SECURITIES United Capital Funding Partnership L.P. ("United Capital") is a special purpose limited partnership in which the Company owns all of the general partner interests. United Capital has $50 million of its monthly income 9⅝% Preferred Capital Securities, Series A, ("Preferred Capital Securities") outstanding, representing limited partnership interests in United Capital. United Capital loaned the proceeds of the issuance and sale of the Preferred Capital Securities to the Company in return for the Company's 9⅝% Junior Subordinated Deferrable Interest Debentures, Series A, Due 2025.

United Capital and the Company have registered an additional $50 million of Capital Securities and/or Subordinated Debentures for sale to the public from time to time, in one or more series, under the Securities Act of 1933.

(E) LONG-TERM DEBT The expenses to issue long-term debt are deferred and amortized over the life of the respective debt issue.

On January 13, 1998, the Company issued and sold $100 million principal amount of 6.25% four-year and 11 month Notes. The yield on the Notes, which were issued at a discount, is 6.30%; and the Notes will mature on December 15, 2002. The proceeds from the sale of the Notes were used to repay $100 million principal amount of 7⅜% Notes, which matured on January 15, 1998.

In March 1998, the Company repurchased $33,798,000 principal amount of 6.20% Notes, at a premium of $178,000, plus accrued interest.

On June 8, 1998, the Company repaid a $50 million Term Loan prior to its August 29, 2000 due date. On June 8, 1998, the Company also repaid $30 million of a $50 million Term Loan prior to its due date of September 6, 2000.

On December 18, 1998, the Company issued and sold $100 million principal amount of 6% five-year Notes. The yield on the Notes, which were issued at a discount, is 6.034%; and the Notes will mature on December 15, 2003. The proceeds from the sale of the Notes were used to repay $66.2 million principal amount of 6.2% Notes, which matured on January 15, 1999, and for general corporate purposes.

On February 1, 1999, the Company converted $7.5 million principal amount Connecticut Development Authority Bonds from a weekly reset mode to a five-year multi-annual mode. The interest rate on the Bonds for the five-year period beginning February 1, 1999 is 4.35% and will be paid semi-annually beginning on August 1, 1999. In addition, on February 1, 1999, the Company converted $98.5 million principal amount Business Finance Authority of the State of New Hampshire Bonds from a weekly reset mode to a multi-annual mode. The interest rate on $27.5 million principal amount of the Bonds is 4.35% for a three-year period beginning February 1, 1999. The interest rate on $71 million principal amount of the Bonds is 4.55% for a five-year period. Interest on the Bonds will be paid semi-annually beginning on August 1, 1999.

Maturities and mandatory redemptions/repayments are set forth below:

(In Thousands of Dollars)	1999	2000	2001	2002	2003
Maturities	$66,202	$70,000	$75,000	$100,000	$100,000
Mandatory redemptions/repayments [1]	3,410	430	333	338	485
Maturities and Mandatory redemptions/repayments	$69,612	$70,430	$75,333	$100,338	$100,485

(1) Principal component of Seabrook lease obligation, net of principal repayment of Seabrook Lease Obligation Bonds held as an investment.

(C) Rate-related Regulatory Proceedings

In April 1998, Connecticut enacted Public Act 98-28 (the Restructuring Act), a massive and complex statute designed to restructure the State's regulated electric utility industry. The business of generating and supplying electricity directly to consumers will be price-deregulated and opened to competition beginning in the year 2000. At that time, these business activities will be separated from the business of delivering electricity to consumers, also known as the transmission and distribution business. The business of delivering electricity will remain with the incumbent franchised utility companies (including the Company), which will continue to be regulated by the DPUC as Distribution Companies. Beginning in 2000, each retail consumer of electricity in Connecticut (excluding consumers served by municipal electric systems) will be able to choose his, her or its supplier of electricity from among competing licensed suppliers, for delivery over the wires system of the franchised Distribution Company. Commencing no later than mid-1999, Distribution Companies will be required to separate on consumers' bills the charge for electricity generation services from the charge for delivering the electricity and all other charges. On July 29, 1998, the DPUC issued the first of what are expected to be several orders relative to this "unbundling" requirement, and has now reopened its proceeding to consider the amount of the generation services charge to be included on consumers' bills.

A major component of the Restructuring Act is the collection, by Distribution Companies, of a "competitive transition assessment," a "systems benefits charge," an "energy conservation and load management program charge" and a "renewable energy investment charge." The competitive transition assessment represents costs that have been reasonably incurred by, or will be incurred by, Distribution Companies to meet their public service obligations as electric companies, and that will likely not otherwise be recoverable in a competitive generation and supply market. These costs include above-market long-term purchased power contract obligations, regulatory asset recovery and above-market investments in power plants (so-called stranded costs). The systems benefits charge represents public policy costs, such as generation decommissioning and displaced worker protection costs. Beginning in 2000, a Distribution Company must collect the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge from all Distribution Company customers, except customers taking service under special contracts predating the Restructuring Act. The Distribution Company will also be required to offer a "standard offer" rate that is, subject to certain adjustments, at least 10% below its fully bundled prices for electricity at rates in effect on December 31, 1996, as discussed below. The standard offer is required, subject to certain adjustments, to be the total rate charged under the standard offer, including generation and transmission and distribution services, the competitive transition assessment, the systems benefits charge, the energy conservation and load management program charge and the renewable energy investment charge.

The Restructuring Act requires that, in order for a Distribution Company to recover any stranded costs associated with its power plants, its fossil-fueled plants must be sold prior to 2000, with any net excess proceeds used to mitigate its recoverable stranded costs, and the Company must attempt to divest its ownership interest in its nuclear-fueled power plants prior to 2004. By October 1, 1998, each Distribution Company was required to file, for the DPUC's approval, an "unbundling plan" to separate, on or before October 1, 1999, all of its power plants that will not have been sold prior to the DPUC's approval of the unbundling plan or will not be sold prior to 2000.

In May of 1998, the Company announced that it would commence selling, through a two-stage bidding process, all of its non-nuclear generation assets, in compliance with the Restructuring Act. On October 2, 1998, the Company agreed to sell both of its operating fossil-fueled generating stations, Bridgeport Harbor Station and New Haven Harbor Station, to Wisvest-Connecticut, LLC, a single-purpose subsidiary of Wisvest Corporation. Wisvest Corporation is a non-utility subsidiary of Wisconsin Energy Corporation, Milwaukee, Wisconsin. The sale price is $272 million in cash, including payment for some non-plant items, and the transaction is expected to close during the spring of 1999. It is contingent upon the receipt of approvals from the DPUC, the Federal Energy Regulatory Commission (FERC), and other federal and state agencies. A petition seeking the DPUC's approval was filed on October 30, 1998 and, on March 5, 1999, the DPUC issued a decision approving the sale. An application seeking the FERC's authorization for the sale of the facilities subject to its jurisdiction was filed on December 21, 1998 and, on February 24, 1999, the FERC issued an order authorizing the sale.

The Company will realize a book gain from the sale proceeds net of taxes and plant investment. However, this gain will be offset by a writedown of other above-market generation costs eligible for the competitive transition assessment, such as regulated plant costs and tax-related regulatory assets or other costs related to the restructuring transition, such that there will be no net income effect of the sale. The Company anticipates using the net cash proceeds from the sale to reduce debt.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, the Company stated that it plans to divest its nuclear generation ownership interests (17.5% of Seabrook Station in New Hampshire and 3.685% of Millstone Station Unit No. 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. The divestiture method has not yet been determined. In anticipation of ultimate divestiture, the Company proposed to satisfy, on a functional basis, the Restructuring Act's requirement that nuclear generating assets be separated from its transmission and distribution assets. This would be accomplished by transferring the nuclear generating assets into a separate new division of the Company, using divisional financial statements and accounting to segregate all revenues, expenses, assets and liabilities associated with nuclear ownership interests.

The Company's unbundling plan also proposes to separate its ongoing regulated transmission and distribution operations and functions, that is, the Distribution Company assets and operations, from all of its unregulated operations and activities. This would be achieved by undergoing a corporate restructuring into a holding company structure. In the holding company structure proposed, the Company will become a wholly-owned subsidiary of a holding company, and each share of the common stock of the Company will be converted into a share of common stock of the holding company. In connection with the formation of the holding company structure, all of the Company's interests in all of its operating unregulated subsidiaries will be transferred to the holding company and, to the extent new businesses are subsequently acquired or commenced, they will also be financed and owned by the holding company. An application for the DPUC's approval of this corporate restructuring was filed on November 13, 1998. DPUC hearings on the corporate unbundling plan and corporate restructuring commenced on February 18, 1999.

Under the Restructuring Act, all Connecticut electricity customers will be able to choose their power supply providers after June 30, 2000. The Company will be required to offer fully-bundled service to customers under a regulated "standard offer" rate and will also become the power supply provider to each customer who does not choose an alternate power supply provider, even though the Company will no longer be in the business of retail power generation. In order to mitigate the financial risk that these regulated service mandates will pose to the Company in an unregulated power generation environment, its unbundling plan proposes that a purchased power adjustment clause be added to its regulated rates, effective July 1, 2000, as permitted by the Restructuring Act. This clause, similar to and based on the purchased gas adjustment clauses used by Connecticut's natural gas local distribution companies, would work in tandem with the Company's procurement of power supplies to assure that "standard offer" customers pay competitive market rates for power supply services and that the Company collects its costs of providing such services. The Distribution Company is also required under the Restructuring Act to provide back-up power supply service to customers whose electric supplier fails to provide power supply services for reasons other than the customers' failure to pay for such services. The Restructuring Act provides for the Distribution Company to recover its reasonable costs of providing this back-up service.

In addition to approval by the DPUC, the several features of the Company's unbundling plan will be subject to approvals and consents by federal regulators, other state and federal agencies, and the Company's common stock shareowners.

On and after January 1, 2000 and until January 1, 2004, the Company will be responsible for providing a "standard offer" service to customers who do not choose an alternate electricity supplier. The "standard offer" prices, including the fully-bundled price of generation, transmission and distribution services, the competitive transition assessment, the systems benefits charge and the energy conservation and renewable energy assessments, must be at least 10% below the average fully-bundled prices in effect on December 31, 1996. The Company has already delivered about 4.8% of this decrease, in price reductions through 1998. The DPUC's 1996 financial and operational review order (see below) anticipated sufficient income in 2000 to accelerate amortization of regulatory assets of about $50 million, equivalent to about 8% of retail revenues. Substantially all of this accelerated amortization may have to be eliminated to allow for the additional "standard offer" price reduction requirement of 10%, at a minimum, while providing for the added costs imposed by the restructuring legislation. The legislation does prescribe certain bases for adjusting the price of standard offer service if the 10% minimum price reduction cannot be accomplished.

On December 31, 1996, the DPUC completed a financial and operational review of the Company and ordered a five-year incentive regulation plan for the years 1997 through 2001 (the Rate Plan). The DPUC did not change the existing retail base rates charged to customers; but the Rate Plan increased amortization of the Company's conservation and load management program investments during 1997-1998, and accelerated the amortization and recovery of unspecified assets during 1999-2001 if the Company's common stock equity return on utility investment exceeds 10.5% after recording the amortization. The Rate Plan also provided for retail price reductions of about 5%, compared to 1996 and phased-in over 1997-2001, primarily through reductions of conservation adjustment mechanism revenues, through a surcredit in each of the five plan years, and through acceptance of the Company's proposal to modify the operation of the fossil fuel clause mechanism. The Company's authorized return on utility common stock equity during the period is 11.5%. Earnings above 11.5%, on an annual basis, are to be utilized one-third for customer price reductions, one-third to increase amortization of regulatory assets, and one-third retained as earnings. As a result of the Rate Plan, customer prices were required to be reduced, on average, by 3% in 1997 compared to 1996. Also as a result of the Rate Plan, customer prices are required to be reduced by an additional 1% in 2000, and another 1% in 2001, compared to 1996. Retail rev-

enues have decreased by approximately 4.8% through 1998 compared to 1996 due to customer price reductions. The Rate Plan was reopened in 1998, in accordance with its terms, to determine the assets to be subjected to accelerated recovery in 1999, 2000 and 2001. The DPUC decided on February 10, 1999 that $12.1 million of the Company's regulatory tax assets will be subjected to accelerated recovery in 1999. The DPUC has not yet determined the assets to be subjected to recovery after 1999. The Rate Plan also includes a provision that it may be reopened and modified upon the enactment of electric utility restructuring legislation in Connecticut and, as a consequence of the 1998 Restructuring Act described above, the Rate Plan may be reopened and modified. However, aside from implementing an additional price reduction in 2000 to achieve the minimum 10% price reduction required by the Restructuring Act and the probable reductions in the accelerated amortizations scheduled in the Rate Plan, the Company is unable to predict, at this time, in what other respects the Rate Plan may be modified on account of this legislation.

(D) Accounting for Phase-in Plan

The Company phased into rate base its allowable investment in Seabrook Unit 1, amounting to $640 million, during the period January 1, 1990 to January 1, 1994. In conjunction with this phase-in plan, the Company was allowed to record a deferred return on the portion of allowable investment excluded from rate base during the phase-in period. Accordingly, the Company is amortizing the net-of-tax accumulated deferred return of $62.9 million over a five-year period that commenced January 1, 1995.

(E) Short-Term Credit Arrangements

The Company has a revolving credit agreement with a group of banks, which currently extends to December 8, 1999. The borrowing limit of this facility is $75 million. The facility permits the Company to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by either the Eurodollar interbank market in London, or by bidding, at the Company's option. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1998, the Company had no short-term borrowings outstanding under this facility.

On June 8, 1998, the Company borrowed $80 million under a new revolving credit agreement with a group of banks. The funds were used to repay $80 million of Term Loans prior to their due dates. The borrowing limit of this facility, which extends to June 7, 1999, is $80 million. The facility permits the Company to borrow funds at a fluctuating interest rate determined by the prime lending market in New York, and also permits the Company to borrow money for fixed periods of time specified by the Company at fixed interest rates determined by the Eurodollar interbank market in London. If a material adverse change in the business, operations, affairs, assets or condition, financial or otherwise, or prospects of the Company and its subsidiaries, on a consolidated basis, should occur, the banks may decline to lend additional money to the Company under this revolving credit agreement, although borrowings outstanding at the time of such an occurrence would not then become due and payable. As of December 31, 1998, the Company had $80 million of short-term borrowings outstanding under this facility.

In addition, as of December 31, 1998, one of the Company's indirect subsidiaries, American Payment Systems, Inc., had borrowings of $6.8 million outstanding under a bank line of credit agreement.

The Company's long-term debt instruments do not limit the amount of short-term debt that the Company may issue. The Company's revolving credit agreement described above requires it to maintain an available earnings/interest charges ratio of not less than 1.5:1.0 for each 12-month period ending on the last day of each calendar quarter. For the 12-month period ended December 31, 1998, this coverage ratio was 3.6:1.0.

Information with respect to short-term borrowings under the Company's revolving credit agreements is as follows:

(In Thousands of Dollars)	1998	1997	1996
Maximum aggregate principal amount of short-term borrowings outstanding at any month-end	$130,000	$50,000	$30,000
Average aggregate short-term borrowings outstanding during the year*	$115,753	$41,441	$15,380
Weighted average interest rate*	6.1%	5.9%	5.7%
Principal amounts outstanding at year-end	$80,000	$30,000	$0
Annualized interest rate on principal amounts outstanding at year-end	5.7%	6.2%	N/A

**Average short-term borrowings represent the sum of daily borrowings outstanding, weighted for the number of days outstanding and divided by the number of days in the period. The weighted average interest rate is determined by dividing interest expense by the amount of average borrowings. Commitment fees of approximately $381,000, $114,000 and $130,000 paid during 1998, 1997 and 1996, respectively, are excluded from the calculation of the weighted average interest rate.*

(F) Income Taxes

(In Thousands of Dollars)	1998	1997	1996
Income tax expense consists of:			
INCOME TAX PROVISIONS:			
Current			
Federal	$36,774	$23,940	$35,398
State	10,685	7,673	11,398
Total current	47,459	31,613	46,796
Deferred			
Federal	1,412	7,008	616
State	(356)	978	(2,892)
Total deferred	1,056	7,986	(2,276)
Investment tax credits	(762)	(762)	(762)
TOTAL INCOME TAX EXPENSE	$47,753	$38,837	$43,758
INCOME TAX COMPONENTS CHARGED AS FOLLOWS:			
Operating expenses	$53,619	$41,333	$53,090
Other income and deductions - net	(5,866)	(2,496)	(9,332)
TOTAL INCOME TAX EXPENSE	$47,753	$38,837	$43,758
The following table details the components of the deferred income taxes:			
Tax depreciation on unrecoverable plant investment	$6,291	$8,089	$5,745
Fossil plants decommissioning reserve	(329)	(7,286)	-
Conservation & load management	(8,026)	(5,768)	(367)
Accelerated depreciation	5,449	5,681	5,617
Pension benefits	3,463	4,911	(9,066)
Seabrook sale/leaseback transaction	304	2,664	(598)
Deferred fossil fuel costs	-	(686)	755
Cancelled nuclear project	(467)	(467)	(4,729)
Unit overhaul and replacement power costs	(1,157)	212	(1,491)
Other - net	(4,472)	636	1,858
DEFERRED INCOME TAXES - NET	$1,056	$7,986	($2,276)

Total income taxes differ from the amounts computed by applying the federal statutory tax rate to income before taxes. The reasons for the differences are as follows:

(In Thousands of Dollars)	1998		1997		1996	
	Pre-Tax	Tax	Pre-Tax	Tax	Pre-Tax	Tax
Computed tax at federal statutory rate		$31,480		$29,619		$28,999
Increases (reductions) resulting from:						
Deferred return-Seabrook Unit 1	12,586	4,405	12,586	4,405	12,586	4,405
ITC taken into income	(762)	(762)	(762)	(762)	(762)	(762)
Allowance for equity funds used during construction	(13)	(5)	(336)	(118)	(940)	(329)
Fossil plant decommissioning reserve	(723)	(253)	(15,591)	(5,457)	-	-
Book depreciation in excess of non-normalized tax depreciation	22,789	7,976	23,926	8,374	22,703	7,946
State income taxes, net of federal income tax benefits	10,329	6,714	8,651	5,622	8,506	5,529
Other items - net	(5,149)	(1,802)	(8,134)	(2,846)	(5,797)	(2,030)
Total income tax expense		$47,753		$38,837		$43,758
Book income before income taxes		$89,943		$84,628		$82,854
Effective income tax rates		53.1%		45.9%		52.8%

At December 31, 1998, the Company had deferred tax liabilities for taxable temporary differences of $430 million and deferred tax assets for deductible temporary differences of $109 million, resulting in a net deferred tax liability of $321 million. Significant components of deferred tax liabilities and assets were as follows: tax liabilities on book/tax plant basis differences and on the cumulative amount of income taxes on temporary differences previously flowed through to ratepayers, $282 million; tax liabilities on normalization of book/tax depreciation timing differences, $127 million and tax assets on the disallowance of plant costs, $41 million.

The Company has reflected on its Consolidated Balance Sheet as of December 31, 1997 an additional amount of deferred tax liabilities associated with plant book/tax basis differences. An offsetting regulatory asset, representing the future amounts to be collected from customers for the recovery of the tax expense associated with these additional tax liabilities, has also been reflected.

(G) Supplementary Information

(In Thousands of Dollars)	1998	1997	1996
OPERATING REVENUES			
Retail	$631,607	$623,571	$649,876
Wholesale - capacity	11,524	9,747	7,686
- energy	33,424	73,124	65,158
Other	9,636	3,825	3,300
TOTAL OPERATING REVENUES	$686,191	$710,267	$726,020
SALES BY CLASS (mWh's) - UNAUDITED			
Retail			
Residential	1,924,724	1,903,096	1,891,988
Commercial	2,324,507	2,253,488	2,258,501
Industrial	1,154,935	1,170,815	1,141,109
Other	48,166	48,717	48,291
	5,452,332	5,376,116	5,339,889
Wholesale	1,551,109	2,700,393	2,260,423
TOTAL SALES BY CLASS	7,003,441	8,076,509	7,600,312
DEPRECIATION			
Plant in service	$67,143	$65,585	$63,618
Accelerated conservation and load management	13,086	6,636	-
Nuclear decommissioning	2,580	2,397	2,303
	$82,809	$74,618	$65,921
OTHER TAXES			
Charged to:			
Operating:			
State gross earnings	$24,039	$23,618	$26,757
Local real estate and personal property (1)	35,088	22,974	24,854
Payroll taxes	5,547	5,948	5,528
	64,674	52,540	57,139
Nonoperating and other accounts	510	459	628
TOTAL OTHER TAXES	$65,184	$52,999	$57,767

(1) 1998 includes $14,025 charge for property tax settlement.

OTHER INCOME AND (DEDUCTIONS) - NET			
Interest income	$3,181	$2,317	$1,505
Equity earnings from Connecticut Yankee	854	1,343	1,225
Loss from subsidiary companies (2)	(6,648)	(814)	(8,422)
Miscellaneous other income and (deductions) - net	(1,190)	1,340	(1,474)
TOTAL OTHER INCOME AND (DEDUCTIONS) - NET	($3,803)	$4,186	($7,166)

(2) Includes before-tax non-recurring charges in 1998 and 1996 of $4,900 and $4,471, respectively.

OTHER INTEREST CHARGES			
Notes Payable	$5,050	$2,462	$882
Other	1,457	818	1,210
TOTAL OTHER INTEREST CHARGES	$6,507	$3,280	$2,092

(H) Pension and Other Benefits

The Company's qualified pension plan, which is based on the highest three years of pay, covers substantially all of its employees, and its entire cost is borne by the Company. The Company also has a non-qualified supplemental plan for certain executives and a non-qualified retiree only plan for certain early retirement benefits. The net pension costs for these plans for 1998, 1997 and 1996 were $(5,138,000), ($4,626,000) and $18,403,000, respectively.

The Company's funding policy for the qualified plan is to make annual contributions that satisfy the minimum funding requirements of ERISA but that do not exceed the maximum deductible limits of the Internal Revenue Code. These amounts are determined each year as a result of an actuarial valuation of the plan In 1996, the Company contributed $2.8 million for 1995 funding requirements. In 1997, the Company contributed $2.7 million for 1996 funding requirements and $2.5 million for 1997 funding requirements. In 1998, the Company contributed $2.6 million for 1998 funding requirements. During 1996, the Company established a supplemental retirement benefit trust and through this trust purchased life insurance policies on the officers of the Company to fund the future liability under the supplemental plan. The cash surrender value of these policies is shown as an investment on the Company's Consolidated Balance Sheet.

The components of net pension costs were as follows:

(In Thousands of Dollars)	1998	1997
Service cost of benefits earned during the period	$4,389	$3,791
Interest cost on projected benefit obligation	17,828	17,565
Expected return on plan assets	(25,934)	(22,293)
Amortization of:		
Prior service cost	406	406
Transition obligation (asset)	(1,095)	(1,065)
Actuarial (gain) loss	(1,132)	(498)
Settlements (curtailments)	400	(2,724)
Other amortization and deferrals - net	-	192
Net pension cost	$(5,138)	$(4,626)

Assumptions used to determine pension costs were:

	1998	1997
Discount rate	7.25%	7.75%
Average wage increase	4.50%	4.50%
Return on plan assets	11.00%	11.00%

The pension benefit obligations and plan assets as of December 31:

(In Thousands of Dollars)	1998	1997
Change in Projected Pension Benefit Obligation:		
Pension Benefit Obligation – January 1	$259,545	$232,783
Service cost	4,389	3,791
Interest cost	17,828	17,565
Curtailments/settlements	-	(3,193)
Actuarial (gain) loss	14,064	21,656
Benefits paid	(15,080)	(13,057)
Pension Benefit Obligation – December 31	$280,746	$259,545
Change in Plan Assets:		
Fair Value of Plan Assets – January 1	$243,739	$208,863
Actual return on plan assets	38,224	43,225
Employer contributions	2,914	5,429
Benefits paid (including expenses)	(16,193)	(13,778)
Fair Value of Plan Assets – December 31	$268,684	$243,739
Funded Status:		
Projected benefits greater than plan assets	$12,062	$15,806
Unrecognized prior service cost	(3,878)	(4,285)
Unrecognized net gain (loss) from past experience	15,639	19,259
Unrecognized transition asset	7,274	8,369
Accrued pension liability	$31,097	$39,149
Assumptions used in estimating benefit obligations at December 31:		
Discount rate	6.75%	7.25%
Average wage increase	4.50%	4.50%

In addition to providing pension benefits, the Company also provides other postretirement benefits (OPEB), consisting principally of health care and life insurance benefits, for retired employees and their dependents. Employees with 25 years of service are eligible for full benefits, while employees with less than 25 years of service but greater than 15 years of service are entitled to partial benefits. Years of service prior to age 35 are not included in determining the number of years of service.

For funding purposes, the Company established a Voluntary Employees' Benefit Association Trust (VEBA) to fund OPEB for union employees. Approximately 44% of the Company's employees are represented by Local 470-1, Utility Workers Union of America, AFL-CIO, for collective bargaining purposes. The Company established a 401(h) account in connection with the qualified pension plan to fund OPEB for non-union employees who retire on or after January 1, 1994. The funding policy assumes contributions to these trust funds to be the total OPEB expense calculated under SFAS No. 106, adjusted to reflect a share of amounts expensed as a result of voluntary early retirement programs minus pay-as-you-go benefit payments for pre-January 1, 1994 non-union retirees, allocated in a manner that minimizes current income tax liability, without exceeding maximum tax deductible limits. In accordance with this policy, the Company contributed approximately $0, $0 and $3.8 million to the union VEBA in 1998, 1997 and 1996, respectively. The Company contributed $0.9 million, $1.7 million and $0.9 million to the 401(h) account in 1998, 1997 and 1996, respectively. Plan assets for both the union VEBA and 401(h) account consist primarily of equity and fixed-income securities.

The components of the net cost of OPEB were as follows:

(In Thousands of Dollars)	1998	1997
Service cost	$1,078	$925
Interest cost	2,576	2,434
Expected return on plan assets	(2,249)	(1,787)
Amortization of:		
Prior service cost	(71)	(86)
Transition obligation (asset)	1,169	1,906
Actuarial (gain) loss	(361)	(648)
Settlements (curtailments)	-	(186)
Other amortization and deferrals - net	-	492
Net Cost of Postretirement Benefit	$2,142	$3,050

Assumptions used to determine OPEB costs were:

	1998	1997
Discount rate	7.25%	7.75%
Health Care Cost Trend Rate	5.50%	5.50%
Return on plan assets	11.00%	11.00%

A one percentage point change in the assumed health care cost trend rate would have the following effects:

(In Thousands of Dollars)	1% Increase	1% Decrease
Aggregate service and interest cost components	$463	$(372)
Accumulated postretirement benefit obligation	$4,246	$(3,498)

The postretirement benefit obligations and plan assets as of December 31:

(In Thousands of Dollars)	1998	1997
Change in Projected Postretirement Benefit Obligation:		
Postretirement Benefit Obligation – January 1	$35,112	$36,220
Service cost	1,078	925
Interest cost	2,576	2,434
Amendments	-	(409)
Curtailments/settlements	-	204
Actuarial (gain) loss	4,002	(1,923)
Benefits paid	(2,539)	(2,339)
Postretirement Benefit Obligation – December 31	$40,229	$35,112
Change in Plan Assets:		
Fair Value of Plan Assets – January 1	$21,168	$16,720
Actual return on plan assets	2,491	3,836
Employer contributions	910	1,737
Benefits paid (including expenses)	(1,366)	(1,125)
Fair Value of Plan Assets – December 31	$23,203	$21,168
Funded Status:		
Projected benefits greater than plan assets	$17,026	$13,944
Unrecognized prior service cost	946	1,017
Unrecognized net gain (loss) from past experience	1,241	5,363
Unrecognized transition asset	(16,368)	(17,537)
Accrued Postretirement liability	$2,845	$2,787
Assumptions used in estimating benefit obligations at December 31:		
Discount rate	6.75%	7.25%
Average wage increase	4.50%	4.50%

The Company has an Employee Savings Plan (401(k) Plan) in which substantially all employees are eligible to participate. The 401(k) Plan enables employees to defer receipt of up to 15% of their compensation and to invest such funds in a number of investment alternatives. The Company makes matching contributions in the form of Company common stock for each employee. During the first five months of 1996, the matching contributions were made into the 401(k) Plan. Beginning in June 1996, the matching contributions were made into the Employee Stock Ownership Plan (ESOP). The Company's matching contribution to the 401(k) Plan during the first five months of 1996 was $0.8 million. In June 1996, all shares of the Company's common stock in the 401(k) Plan were transferred to the ESOP.

The Company has an ESOP for substantially all its employees. In June 1996, the Company began making matching contributions to the ESOP based on each employee's salary deferrals in the 401(k) Plan. The matching contribution currently equals fifty cents for each dollar of the employee's compensation deferred, but is not more than 3⅝% of the employee's annual salary. The Company's matching contributions to the ESOP during 1998, 1997 and the period June 1996 – December 1996 were $1.7 million, $1.7 million and $0.8 million, respectively.

The Company pays dividends on the shares of stock in the ESOP to the participant and the Company receives a tax deduction on the dividends paid. The Company also makes contributions to the ESOP equal to 25% of the dividends paid to each participant. The Company's annual contributions during 1998, 1997 and 1996 were $270,000, $417,000 and $324,000, respectively.

(I) Jointly-Owned Plant

At December 31, 1998, the Company had the following interests in jointly owned plants:

(In Millions Except Share Amounts)	Ownership/ Leasehold Share	Plant in Service	Accumulated Depreciation
Seabrook Unit 1	17.5 %	$648	$146
Millstone Unit 3	3.685	135	63
New Haven Harbor Station	93.7	143	78

The Company's share of the operating costs of jointly owned plants is included in the appropriate expense captions in the Consolidated Statement of Income.

(J) Unamortized Cancelled Nuclear Project

From December 1984 through December 1992, the Company had been recovering its investment in Seabrook Unit 2, a partially constructed nuclear generating unit that was cancelled in 1984, over a regulatory approved ten-year period without a return on its unamortized investment. In the Company's 1992 rate decision, the DPUC adopted a proposal by the Company to write off its remaining investment in Seabrook Unit 2, beginning January 1, 1993, over a 24-year period, corresponding with the flowback of certain Connecticut Corporation Business Tax (CCBT) credits. Such decision will allow the Company to retain the Seabrook Unit 2/CCBT amounts for ratemaking purposes, with the accumulated CCBT credits not deducted from rate base during the 24-year period of amortization in recognition of a longer period of time for amortization of the Seabrook Unit 2 balance. As a result of reducing its remaining unamortized investment in Seabrook Unit 2 with proceeds from the sale of certain Seabrook Unit 2 equipment, the Company expects to completely amortize its unamortized investment in the year 2008.

(K) Fuel Financing Obligations and Other Lease Obligations

The Company has a Fossil Fuel Supply Agreement with a financial institution providing for the financing of up to $37.5 million of fossil fuel purchases. Under this agreement, the financing entity may acquire and/or store natural gas, coal and fuel oil for sale to the Company, and the Company may purchase these fossil fuels from the financing entity at a price for each type of fuel that reimburses the financing entity for the direct costs it has incurred in purchasing and storing the fuel, plus a charge for maintaining an inventory of the fuel determined by reference to the fluctuating interest rate on thirty-day, dealer-placed commercial paper in New York. The Company is obligated to insure the fuel inventories and to indemnify the financing entity against all liabilities, taxes and other expenses incurred as a result of its ownership, storage and sale of fossil fuel to the Company. This agreement currently extends to March 2000. At December 31, 1998, no fossil fuel purchases were being financed under this agreement.

The Company also has lease arrangements for data processing equipment, office equipment, vehicles and office space, including the lease of a distribution service facility, which is recognized as a capital lease. The gross amount of assets recorded under capital leases and the related obligations of those leases as of December 31, 1998 are recorded on the balance sheet.

Future minimum lease payments under capital leases, excluding the Seabrook sale/leaseback transaction, which is being treated as a long-term financing, are estimated to be as follows:

(In Thousands of Dollars)	
1999	$1,696
2000	1,696
2001	1,696
2002	1,696
2003	1,696
After 2003	16,000
Total minimum capital lease payments	24,480
Less: Amount representing interest	7,626
Present value of minimum capital lease payments	$16,854

Capitalization of leases has no impact on income, since the sum of the amortization of a leased asset and the interest on the lease obligation equals the rental expense allowed for ratemaking purposes.

Operating leases, which are charged to operating expense, consist principally of a large number of small, relatively short-term, renewable agreements for a wide variety of equipment. In addition, the Company has an operating lease for its corporate headquarters. Future minimum lease payments under this lease are estimated to be as follows:

(In Thousands of Dollars)	
1999	$6,426
2000	6,524
2001	6,837
2002	8,168
2003	9,125
2004-2012	91,209
Total	$128,289

Rental payments charged to operating expenses in 1998, 1997 and 1996, including rental payments for its corporate headquarters, were $11.7 million, $12.2 million and $12.8 million, respectively.

(L) Commitments and Contingencies

CAPITAL EXPENDITURE PROGRAM The Company's continuing capital expenditure program is presently estimated at $130.8 million, excluding AFUDC, for 1999 through 2003.

NUCLEAR INSURANCE CONTINGENCIES The Price-Anderson Act, currently extended through August 1, 2002, limits public liability resulting from a single incident at a nuclear power plant. The first $200 million of liability coverage is provided by purchasing the maximum amount of commercially available insurance. Additional liability coverage will be provided by an assessment of up to $83.9 million per incident, levied on each of the nuclear units licensed to operate in the United States, subject to a maximum assessment of $10 million per incident per nuclear unit in any year. In addition, if the sum of all public liability claims and legal costs resulting from any nuclear incident exceeds the maximum amount of financial protection, each reactor operator can be assessed an additional 5% of $83.9 million, or $4.2 million. The maximum assessment is adjusted at least every five years to reflect the impact of inflation. With respect to each of the three nuclear generating units in which the Company has an interest,

the Company will be obligated to pay its ownership and/or leasehold share of any statutory assessment resulting from a nuclear incident at any nuclear generating unit. Based on its interests in these nuclear generating units, the Company estimates its maximum liability would be $17.8 million per incident. However, any assessment would be limited to $2.1 million per incident per year.

The NRC requires each nuclear generating unit to obtain property insurance coverage in a minimum amount of $1.06 billion and to establish a system of prioritized use of the insurance proceeds in the event of a nuclear incident. The system requires that the first $1.06 billion of insurance proceeds be used to stabilize the nuclear reactor to prevent any significant risk to public health and safety and then for decontamination and cleanup operations. Only following completion of these tasks would the balance, if any, of the segregated insurance proceeds become available to the unit's owners. For each of the three nuclear generating units in which the Company has an interest, the Company is required to pay its ownership and/or leasehold share of the cost of purchasing such insurance. Although each of these units has purchased $2.75 billion of property insurance coverage, representing the limits of coverage currently available from conventional nuclear insurance pools, the cost of a nuclear incident could exceed available insurance proceeds. Under those circumstances, the nuclear insurance pools that provide this coverage may levy assessments against the insured owner companies if pool losses exceed the accumulated funds available to the pool. The maximum potential assessments against the Company with respect to losses occurring during current policy years are approximately $3.1 million.

OTHER COMMITMENTS AND CONTINGENCIES

○ **CONNECTICUT YANKEE** On December 4, 1996, the Board of Directors of the Connecticut Yankee Atomic Power Company (Connecticut Yankee) voted unanimously to retire the Connecticut Yankee nuclear plant (the Connecticut Yankee Unit) from commercial operation. The Company has a 9.5% stock ownership share in Connecticut Yankee. The power purchase contract under which the Company has purchased its 9.5% entitlement to the Connecticut Yankee Unit's power output permits Connecticut Yankee to recover 9.5% of all of its costs from UI. In December of 1996, Connecticut Yankee filed decommissioning cost estimates and amendments to the power contracts with its owners with the Federal Energy Regulatory Commission (FERC). Based on regulatory precedent, this filing seeks confirmation that Connecticut Yankee will continue to collect from its owners its decommissioning costs, the unrecovered investment in the Connecticut Yankee Unit and other costs associated with the permanent shutdown of the Connecticut Yankee Unit. On August 31, 1998, a FERC Administrative Law Judge (ALJ) released an initial decision regarding Connecticut Yankee's December 1996 filing. The initial decision contains provisions that would allow Connecticut Yankee to recover, through the power contracts with its owners, the balance of its net unamortized investment in the Connecticut Yankee Unit, but would disallow recovery of a portion of the return on Connecticut Yankee's investment in the unit. The ALJ's decision also states that decommissioning cost collections by Connecticut Yankee, through the power contracts, should continue to be based on a previously-approved estimate until a new, more reliable estimate has been prepared and tested. During October of 1998, Connecticut Yankee and its owners filed briefs setting forth exceptions to the ALJ's initial decision. If this initial decision is upheld by the FERC, Connecticut Yankee could be required to write off a portion of the regulatory asset on its Balance Sheet associated with the retirement of the Connecticut Yankee Unit. In this event, however, the Company would not be required to record any write-off on account of its 9.5% ownership share in Connecticut Yankee, because the Company has recorded its regulatory asset associated with the retirement of the Connecticut Yankee Unit net of any return on investment. The Company cannot predict, at this time, the outcome of the FERC proceeding. However, the Company will continue to support Connecticut Yankee's efforts to contest the ALJ's initial decision.

The Company's estimate of its remaining share of Connecticut Yankee costs, including decommissioning, less return of investment (approximately $9.9 million) and return on investment (approximately $4.7 mil-

lion) at December 31, 1998, is approximately $32.7 million. This estimate, which is subject to ongoing review and revision, has been recorded by the Company as an obligation and a regulatory asset on the Consolidated Balance Sheet.

○ **HYDRO-QUEBEC** The Company is a participant in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. Phase I of this facility, which became operational in 1986 and in which the Company has a 5.45% participating share, has a 690 megawatt equivalent capacity value; and Phase II, in which the Company has a 5.45% participating share, increased the equivalent capacity value of the intertie from 690 megawatts to a maximum of 2000 megawatts in 1991. A ten-year Firm Energy Contract, which provides for the sale of 7 million megawatt-hours per year by Hydro-Quebec to the New England participants in the Phase II facility, became effective on July 1, 1991. Additionally, the Company is obligated to furnish a guarantee for its participating share of the debt financing for the Phase II facility. As of December 31, 1998, the Company's guarantee liability for this debt was approximately $6.8 million.

○ **PROPERTY TAXES** The City of New Haven (the City) and the Company have been involved in a dispute over the amount of personal property taxes owed to the City for tax years beginning with 1991-1992. On May 8, 1998, the City and the Company reached a comprehensive settlement of all of the Company's contested personal property tax assessments and tax bills for the tax years 1991-1992 through 1997-1998 and the Company's personal property tax assessments for the tax year 1998-1999 and subsequent years. Under the terms of this settlement, the Company agreed to pay the City $14.025 million, subject to Connecticut Superior Court approval of the settlement and conditioned on the Company receiving authorization from the DPUC to recover the settlement amount from its retail customers. The DPUC denied the Company's initial application for such authorization and the City agreed to extend to December 31, 1998 the time period for satisfying this condition of the settlement in return for a payment by the Company of $6 million. The Company filed a second application with the DPUC on July 9, 1998, and on December 8, 1998 a Joint Stipulation among the Company, the Office of Consumer Counsel and the Connecticut Attorney General relative to the recovery of the settlement amount was filed with the DPUC. On December 30, 1998, the DPUC issued a draft decision rejecting this Joint Stipulation. The Company filed written exceptions to this draft decision and requested oral argument on the draft decision; and the City agreed to extend to March 1, 1999 the time period for obtaining a favorable DPUC authorization, in return for payment by the Company of an additional $6 million. On February 10, 1999, the DPUC issued a final decision rejecting the Joint Stipulation. The Company subsequently waived the condition to the settlement with the City that the DPUC authorize recovery of the settlement amount from the Company's retail customers and, on March 5, 1999, the settlement was approved by the Superior Court. The Company will pay the remaining $2.025 million of the settlement amount to the City promptly. Based on the DPUC's final decision, the Company has expensed the $14.025 million settlement amount in 1998.

○ **ENVIRONMENTAL CONCERNS** In complying with existing environmental statutes and regulations and further developments in areas of environmental concern, including legislation and studies in the fields of water and air quality (particularly "air toxics" and "global warming"), hazardous waste handling and disposal, toxic substances, and electric and magnetic fields, the Company may incur substantial capital expenditures for equipment modifications and additions, monitoring equipment and recording devices, and it may incur additional operating expenses. Litigation expenditures may also increase as a result of scientific investigations, and speculation and debate, concerning the possibility of harmful health effects of electric and magnetic fields. The total amount of these expenditures is not now determinable.

○ **SITE DECONTAMINATION, DEMOLITION AND REMEDIATION COSTS** The Company has estimated that the total cost of decontaminating and demolishing its Steel Point Station and completing requisite environmental remediation of the site will be approximately $11.3 million, of which approximately $8.3 million had been incurred as of December 31, 1998, and that the value of the property following

remediation will not exceed $6.0 million. As a result of a 1992 DPUC retail rate decision, beginning January 1, 1993, the Company has been recovering through retail rates $1.075 million of the remediation costs per year. The remediation costs, property value and recovery from customers will be subject to true-up in the Company's next retail rate proceeding based on actual remediation costs and actual gain on the Company's disposition of the property.

The Company is presently remediating an area of PCB contamination at a site, bordering the Mill River in New Haven, that contains transmission facilities and the deactivated English Station generation facilities. Remediation costs, including the repair and/or replacement of approximately 560 linear feet of sheet piling, are currently estimated at $7.5 million. In addition, the Company is planning to repair and/or replace the remaining deteriorated sheet piling bordering the English Station property, at an additional estimated cost of $10 million.

As described at Note (C) "Rate-Regulated Regulatory Proceedings" above, the Company has contracted to sell its Bridgeport Harbor Station and New Haven Harbor Station generating plants in compliance with Connecticut's electric utility industry restructuring legislation. Environmental assessments performed in connection with the marketing of these plants indicate that substantial remediation expenditures will be required in order to bring the plant sites into compliance with applicable Connecticut minimum standards following their sale. The proposed purchaser of the plants has agreed to undertake and pay for the major portion of this remediation. However, the Company will be responsible for remediation of the portions of the plant sites that will be retained by it.

(M) Nuclear Fuel Disposal and Nuclear Plant Decommissioning

Costs associated with nuclear plant operations include amounts for disposal of nuclear wastes, including spent fuel, and for the ultimate decommissioning of the plants. Under the Nuclear Waste Policy Act of 1982, the federal Department of Energy (DOE) is required to design, license, construct and operate a permanent repository for high level radioactive wastes and spent nuclear fuel. The Act requires the DOE to provide for the disposal of spent nuclear fuel and high level radioactive waste from commercial nuclear plants through contracts with the owners and generators of such waste; and the DOE has established disposal fees that are being paid to the federal government by electric utilities owning or operating nuclear generating units. In return for payment of the prescribed fees, the federal government was required to take title to and dispose of the utilities' high level wastes and spent nuclear fuel beginning no later than January 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010 and possibly not earlier than 2013, notwithstanding the DOE's statutory and contractual responsibility to begin disposal of high-level radioactive waste and spent fuel beginning not later than January 31, 1998.

The DOE also announced that, absent a repository, the DOE has no statutory obligation to begin taking high level wastes and spent nuclear fuel for disposal by January 1998. However, numerous utilities and states have obtained a judicial declaration that the DOE has a statutory responsibility to take title to and dispose of high level wastes and spent nuclear fuel beginning in January 1998, and that the contracts between the DOE and the plant owners and generators of such waste will provide a potentially adequate remedy for the latter if the DOE fails to fulfill its contractual obligations by that date. The DOE is contesting these judicial declarations; and it is unclear at this time whether the United States Congress will enact legislation to address spent fuel/high level waste disposal issues.

Until the federal government begins receiving such materials, nuclear generating units will need to retain high level wastes and spent nuclear fuel on-site or make other provisions for their storage. Storage facilities for the Connecticut Yankee Unit are deemed adequate, and storage facilities for Millstone Unit 3 are

expected to be adequate for the projected life of the unit. Storage facilities for Seabrook Unit 1 are expected to be adequate until at least 2010. Fuel consolidation and compaction technologies are being considered for Seabrook Unit 1 and may provide adequate storage capability for the projected life of the unit. In addition, other licensed technologies, such as dry storage casks, may satisfy spent nuclear fuel storage requirements.

Disposal costs for low-level radioactive wastes (LLW) that result from operation or decommissioning of nuclear generating units have increased significantly in recent years and may continue to rise. The cost increases are a function of increased packaging and transportation costs, and higher fees and surcharges imposed by the disposal facilities. Currently, the Chem Nuclear LLW facility at Barnwell, South Carolina, is open to the Connecticut Yankee Unit, Millstone Unit 3, and Seabrook Unit 1 for disposal of LLW. The Envirocare LLW facility at Clive, Utah, is also open to these generating units for portions of their LLW. All three units have contracts in place for LLW disposal at these disposal facilities.

Because access to LLW disposal may be lost at any time, Millstone Unit 3 and Seabrook Unit 1 have storage plans that will allow on-site retention of LLW for at least five years in the event that disposal is interrupted. The Connecticut Yankee Unit, which has been retired from commercial operation, has a similar storage program, although disposal of its LLW will take place in connection with its decommissioning.

The Company cannot predict whether or when a LLW disposal site will be designated in Connecticut. The State of New Hampshire has not met deadlines for compliance with the Low-Level Radioactive Waste Policy Act and has stated that the state is unsuitable for a LLW disposal facility. Both Connecticut and New Hampshire are also pursuing other options for out-of-state disposal of LLW.

NRC licensing requirements and restrictions are also applicable to the decommissioning of nuclear generating units at the end of their service lives, and the NRC has adopted comprehensive regulations concerning decommissioning planning, timing, funding and environmental reviews. UI and the other owners of the nuclear generating units in which UI has interests estimate decommissioning costs for the units and attempt to recover sufficient amounts through their allowed electric rates, together with earnings on the investment of funds so recovered, to cover expected decommissioning costs. Changes in NRC requirements or technology, as well as inflation, can increase estimated decommissioning costs.

New Hampshire has enacted a law requiring the creation of a government-managed fund to finance the decommissioning of nuclear generating units in that state. The New Hampshire Nuclear Decommissioning Financing Committee (NDFC) has established $497 million (in 1999 dollars) as the decommissioning cost estimate for Seabrook Unit 1, of which the Company's share would be approximately $87 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 36-year energy producing life. Monthly decommissioning payments are being made to the state-managed decommissioning trust fund. UI's share of the decommissioning payments made during 1998 was $2.1 million. UI's share of the fund at December 31, 1998 was approximately $16.5 million.

Connecticut has enacted a law requiring the operators of nuclear generating units to file periodically with the DPUC their plans for financing the decommissioning of the units in that state. The current decommissioning cost estimate for Millstone Unit 3 is $560 million (in 1999 dollars), of which the Company's share would be approximately $21 million. This estimate assumes the prompt removal and dismantling of the unit at the end of its estimated 40-year energy producing life. Monthly decommissioning payments, based on these cost estimates, are being made to a decommissioning trust fund managed by Northeast Utilities (NU). UI's share of the Millstone Unit 3 decommissioning payments made during 1998 was $487,000. UI's share of the fund at December 31, 1998 was approximately $6.5 million. The current decommissioning cost estimate for the Connecticut Yankee Unit, assuming the prompt removal and dismantling of

the unit commencing in 1997, is $476 million, of which UI's share would be $45 million. Through December 31, 1998, $85 million has been expended for decommissioning. The projected remaining decommissioning cost is $391 million, of which UI's share would be $37 million. The decommissioning trust fund for the Connecticut Yankee Unit is also managed by NU. For the Company's 9.5% equity ownership in Connecticut Yankee, decommissioning costs of $2.4 million were funded by UI during 1998, and UI's share of the fund at December 31, 1998 was $25 million.

The Financial Accounting Standards Board (FASB) has issued an exposure draft related to the accounting for the closure and removal costs of long-lived assets, including nuclear plant decommissioning. If the proposed accounting standard were adopted, it may result in higher annual provisions for decommissioning to be recognized earlier in the operating life of nuclear units and an accelerated recognition of the decommissioning obligation. The FASB will be deliberating this issue, and the resulting final pronouncement could be different from that proposed in the exposure draft.

(N) Fair Value of Financial Instruments (1)

The estimated fair values of the Company's financial instruments are as follows:

(In Thousands of Dollars)	1998		1997	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and temporary cash investments	$101,445	$101,445	$32,002	$32,002
Long-term debt (2)(3)(4)	$606,342	$611,524	$620,457	$624,192

(1) Equity investments were not valued because they were not considered to be material.
(2) Excludes the obligation under the Seabrook Unit 1 sale/leaseback agreement.
(3) The fair market value of the Company's long-term debt is estimated by brokers based on market conditions at December 31, 1998 and 1997, respectively.
(4) See Note (B), Capitalization - Long-Term Debt.

(O) Quarterly Financial Data (Unaudited)

Selected quarterly financial data for 1998 and 1997 are set forth below:

(In Thousands of Dollars Except Per Share Amount) Quarter	Operating Revenues	Operating Income	Net Income	Earnings per share of common stock (1) Basic	Diluted
1998					
First	$162,474	$22,677	$8,962	$.64	$.64
Second (2)	159,792	21,174	5,497	.39	.39
Third	198,601	37,462	26,236	1.87	1.87
Fourth (3)	165,324	15,013	1,495	.10	.10
1997					
First	$180,325	$22,150	$7,710	$.54	$.54
Second (4)(5)	163,774	22,692	8,542	.61	.61
Third	196,563	38,351	23,402	1.68	1.68
Fourth	169,605	21,380	6,137	.44	.44

(1) Based on weighted average number of shares outstanding each quarter.
(2) Net income and earnings per share for the second quarter of 1998 included an after-tax charge of $2.9 million, for losses associated with the Company's unregulated subsidiaries.
(3) Operating income, net income and earnings per share for the fourth quarter of 1998 included an after-tax charge of $8.3 million, associated with a property tax settlement. See Note (L), "Commitments and Contingencies – Property Taxes".
(4) Operating income, net income and earnings per share for the second quarter of 1997 included an after-tax credit of $6.7 million, or $.48 per share, to provide for the cumulative tax benefits associated with future fossil generation decommissioning.
(5) Operating income, net income and earnings per share for the second quarter of 1997 included an after-tax charge of $4.1 million, or $.30 per share, to record additional amortization of conservation and load management costs.

Market for the Company's Common Equity and Related Shareowner Matters

UI's Common Stock is traded on the New York Stock Exchange, where the high and low sale prices during 1998 and 1997 were as follows:

	1998 Sale Price High	Low	1997 Sale Price High	Low
First Quarter	48 9/16	42 5/8	32 5/8	24 1/2
Second Quarter	51 15/16	46 15/16	30 7/8	24 1/2
Third Quarter	53 9/16	49	37	31 1/2
Fourth Quarter	53 3/4	48 1/16	45 15/16	37

UI has paid quarterly dividends on its Common Stock since 1900. The quarterly dividends declared in 1997 and 1998 were at a rate of 72 cents per share.

The indenture under which $266.2 million principal amount of Notes are issued places limitations on the payment of cash dividends on common stock and on the purchase or redemption of common stock. Retained earnings in the amount of $105.7 million were free from such limitations at December 31, 1998.

As of December 31, 1998, there were 14,735 Common Stock shareowners of record.

Selected Financial Data

	1998	1997	1996
FINANCIAL RESULTS OF OPERATION (THOUSANDS)			
Sales of Electricity			
Retail			
Residential	$262,974	$259,842	$265,562
Commercial	254,765	248,984	263,609
Industrial	102,201	102,967	108,825
Other	11,667	11,778	11,880
TOTAL RETAIL	631,607	623,571	649,876
Wholesale (1)	44,948	82,871	72,844
Other operating revenues	9,636	3,825	3,300
TOTAL OPERATING REVENUES	686,191	710,267	726,020
Fuel and interchange energy -net			
Retail-own load	116,769	109,542	95,359
Wholesale	34,775	73,124	65,158
Capacity purchased-net	34,515	39,976	46,830
Depreciation	82,809 (3)	74,618 (3)	65,921
Other amortization, principally deferred return and cancelled plant	13,758	13,758	13,758
Other operating expenses, excluding tax expense	188,946	200,803	219,630 (7
Gross earnings tax	24,039	23,618	26,757
Other non-income taxes	40,635 (4)	28,922	30,382
TOTAL OPERATING EXPENSES, EXCLUDING INCOME TAXES	536,246	564,361	563,795
Deferred return - Seabrook Unit 1	0	0	0
AFUDC	468	1,575	2,375
Other non-operating income(loss)	(3,803) (5)	4,186	(7,166) (5
Interest expense			
Long-term debt - net	42,836	56,158	65,046
Other	9,018	6,068	4,721
TOTAL	51,854	62,226	69,767
Minority interest in preferred securities	4,813	4,813	4,813
Income tax expense			
Operating income tax	53,619	41,333 (6)	53,090
Non-operating income tax	(5,866)	(2,496)	(9,332)
TOTAL	47,753	38,837	43,758
Income (loss) before cumulative effect of accounting change	42,190	45,791	39,096
Cumulative effect of change in accounting - net of tax	0	0	0
Net income (loss)	42,190	45,791	39,096 (8)
Discount on preferred stock redemption	(21)	(48)	(1,840)
Preferred and preference stock dividends	201	205	330
Income (loss) applicable to common stock	$42,010	$45,634	$40,606
OPERATING INCOME	$96,326	$104,573	$109,135
FINANCIAL CONDITION (THOUSANDS)			
Plant in service-net	$1,172,555	$1,222,174	$1,258,306
Construction work in progress	33,695	25,448	40,998
Plant-related regulatory asset	0	0	0
Other property and investments	58,047	58,441	49,091
Current assets	255,365	165,027	163,350
Deferred charges and regulatory assets	371,674	408,993	449,150
TOTAL ASSETS	$1,891,336	$1,880,083	$1,960,895
Common stock equity	$445,507	$438,963	$440,016
Preferred, preference stock and preferred securities	54,299	54,351	54,461
Long-term debt excluding current portion	664,510	644,670	759,680
Non-current liabilities (9)	109,981	119,868	138,816
Current portion of long-term debt	66,202	100,000	69,900
Notes payable	86,892	37,751	10,965
Other current liabilities (9)	123,006	130,993	129,007
Deferred income tax liabilities and other	340,939	353,487	358,050
TOTAL CAPITALIZATION & LIABILITIES	$1,891,336	$1,880,083	$1,960,895

(1) Operating Revenues, for years prior to 1992, include wholesale power exchange contract sales that were reclassified from Fuel and Capacity expenses in accordance with Federal Energy Regulatory Commission requirements.
(2) Includes reclassification of certain Commercial and Industrial customers.
(3) Includes the before-tax effect of charges for additional amortization of conservation & load management costs: $13.1 million in 1998 and $6.6 million in 1997.
(4) Includes the effect of charges of $14.0 million, before-tax, associated with property tax settlement.
(5) Includes the before-tax effect of charges for losses associated with unregulated subsidiaries: $4.9 million in 1998 and $4.5 million in 1996

1995	1994	1993	1992	1991	1990	1989
$260,694	$252,386	$238,185	$226,455	$226,751	$211,891	$205,183
259,715	250,771	256,559	253,456 (2)	255,782	234,704	219,852
106,963	104,242	97,466	97,010 (2)	91,895	94,526	92,855
11,736	11,469	11,349	11,065	10,886	10,536	9,943
639,108	618,868	603,559	587,986	585,314	551,657	527,833
48,232	34,927	45,931	75,484	84,236	85,657	77,925
3,109	2,953	3,533	3,855	3,821	3,332	3,348
690,449	656,748	653,023	667,325	673,371	640,646	609,106
96,538	99,589	98,694	108,084	123,010	119,285	128,739
41,631	27,765	39,356	55,169	61,858	69,117	62,681
47,420	44,769	47,424	43,560	44,668	42,827	50,234
61,426	58,165	56,287	50,706	48,181	36,526	35,618
13,758	1,172	1,780	10,415	10,415	4,173	10,415
183,749	193,098	203,427 (10)	183,426	178,912	176,419	144,867
27,379	27,403	27,955	27,362	27,223	25,595	24,506
31,564	32,458	29,977	31,869	28,673	24,648	20,294
503,465	484,419	504,900	510,591	522,940	498,590	477,354
0	0	7,497	15,959	17,970	21,503	0
2,762	3,463	4,067	3,232	5,190	3,443	65,443
(4,272)	(1,907)	71	18,545	2,697	22,654	(219,742)
63,431	73,772	80,030	88,666	90,296	94,056	91,126
13,140	10,301	12,260	12,882	9,847	15,468	22,849
76,571	84,073	92,290	101,548	100,143	109,524	113,975
3,583	0	0	0	0	0	0
59,828	44,937	33,309	48,712	47,231	43,493	37,963
(4,901)	(3,214)	(6,322)	(12,558)	(19,299)	(17,409)	(101,135)
54,927	41,723	26,987	36,154	27,932	26,084	(63,172)
50,393	48,089	40,481	56,768	48,213	54,048	(73,350)
0	(1,294)	0	0	7,337	0	0
50,393	46,795	40,481 (11)	56,768	55,550	54,048	(73,350)
(2,183)	0	0	0	0	0	0
1,329	3,323	4,318	4,338	4,530	4,751	8,233
$51,247	$43,472	$36,163	$52,430	$51,020	$49,297	($81,583)
$127,156	$127,392	$114,814	$108,022	$103,200	$98,563	$93,789
$1,277,910	$1,268,145	$1,243,426	$1,224,058	$1,219,871	$1,209,173	$562,473
41,817	57,669	77,395	59,809	54,771	50,257	675,831
0	0	0	0	0	0	81,768
53,355	53,267	58,096	65,320	79,009	90,006	91,648
137,277	157,309	187,981	247,954	164,839	161,066	170,823
475,258	538,601	567,394	556,493	554,365	553,986	605,696
$1,985,617	$2,074,991	$2,134,292	$2,153,634	$2,072,855	$2,064,488	$2,188,239
$439,981	$428,028	$423,324	$422,746	$401,771	$379,812	$362,584
60,539	44,700	60,945	60,945	62,640	69,700	70,00
845,684	708,340	875,268	893,457	909,998	899,993	868,884
65,747	59,458	62,666	44,567	110,217	110,850	117,200
40,800	193,133	143,333	92,833	37,500	41,667	18,667
0	67,000	0	84,099	13,000	15,000	45,000
102,336	122,084	117,343	114,757	114,280	138,173	133,459
430,530	452,248	451,413	440,230	423,449	409,293	572,445
$1,985,617	$2,074,991	$2,134,292	$2,153,634	$2,072,855	$2,064,488	$2,188,239

(6) Includes the effect of credits of $6.7 million to provide tax provision for fossil generation decommissioning.
(7) Includes the effect of charges of $23.0 million, before-tax, associated with voluntary early retirement programs.
(8) Includes the effect of charges of $13.4 million, after-tax, associated with voluntary early retirement programs.
(9) Amounts for years prior to 1996 were reclassified in 1996.
(10) Includes the effect of a reorganization charge of $13.6 million, before-tax, associated with a voluntary early retirement program.
(11) Includes the effect of a reorganization charge of $7.8 million, after-tax.

Selected Financial Data (continued)

	1998	1997	1996
COMMON STOCK DATA			
Average number of shares outstanding	14,017,644	13,975,802	14,100,806
Number of shares outstanding at year-end	14,034,562	13,907,824	14,101,291
Earnings (loss) per share (average) - basic	$3.00	$3.27	$2.88
Earnings (loss) per share (average) - diluted	$3.00	$3.26	$2.87
Recurring earnings (loss) per share (average) (1)	$3.42	$3.11	$3.94
Book value per share	$31.74	$31.56	$31.20
Average return on equity			
Total	9.44%	10.45%	9.20%
Utility	11.43%	11.54%	11.51%
Dividends declared per share	$2.88	$2.88	$2.88
Market Price:			
High	$53.750	$45.9375	$39.750
Low	$42.625	$24.5000	$31.375
Year-end	$51.500	$45.9375	$31.375
Net cash provided by operating activities, less dividends ($000's)	$69,573	$127,807	$103,943
Capital expenditures, excluding AFUDC	$38,040	$33,436	$47,174
OTHER FINANCIAL AND STATISTICAL DATA			
Sales by class (MWh's)			
Residential	1,924,724	1,903,096	1,891,988
Commercial	2,324,507	2,253,488	2,258,501
Industrial	1,154,935	1,170,815	1,141,109
Other	48,166	48,717	48,291
Total	5,452,332	5,376,116	5,339,889
Number of retail customers by class (average)			
Residential	281,591	280,283	279,024
Commercial	29,468	29,228	28,666
Industrial	1,752	1,697	1,652
Other	1,172	1,163	1,141
Total	313,983	312,371	310,483
Revenue per kilowatt hour by class (cents)			
Residential	13.66	13.65	14.04
Commercial	10.96	11.05	11.67
Industrial	8.85	8.79	9.54
Average large industrial customers time of use rate (cents)	8.16	8.12	8.26
System requirements (MWh)	5,728,222	5,631,296	5,640,957
Peak load - kilowatts	1,142,670	1,173,160	1,044,620
Generating capability- peak (kilowatts)	1,323,380	1,356,100	1,522,350
Load factor	57.23%	54.80%	61.64%
Fuel generation mix percentages			
Coal	21	44	38
Oil	46	15	8
Nuclear	23	25	37
Cogeneration	6	9	9
Gas	0	2	3
Hydro	4	5	5
Revenues - retail sales ($000's)			
Base	$629,446	$621,874	$642,106
Base rate adjustments	2,161	1,697	7,770
Sales provision adjustment	0	0	0
Total	$631,607	$623,571	$649,876
Revenues - retail sales per kWh (cents)			
Base	11.54	11.57	12.02
Base rate adjustments	0.04	0.03	0.15
Sales provision adjustment	0.00	0.00	0.00
Total	11.58	11.60	12.17
Fuel and energy cost per kWh (cents)	2.04	1.95	1.69
Fossil	2.60	2.39	2.41
Nuclear	0.58	0.61	0.46
Number of employees at year-end	1,193	1,175	1,287
Total payroll ($000 'S)	$65,294	$68,640	$69,276

(1) Recurring earnings (loss) per share (average) is not a generally accepted accounting principle measurement. Management provides this measurement for informational purposes only.

1995	1994	1993	1992	1991	1990	1989
14,089,835	14,085,452	14,063,854	13,941,150	13,899,906	13,887,748	13,887,748
14,100,091	14,086,691	14,083,291	14,033,148	13,932,348	13,887,748	13,887,748
$3.64	$3.09	$2.57	$3.76	$3.67	$3.55	($5.87)
$3.63	$3.08	$2.56	$3.74	$3.66	$3.55	($5.87)
$3.61	$3.28	$3.13	$3.17	$2.90	$3.55	($5.87)
$31.20	$30.39	$30.06	$30.12	$28.84	$27.35	$26.11
11.84%	10.19%	8.45%	12.67%	13.01%	13.39%	-18.88%
13.04%	12.50%	10.97%	14.46%	13.39%	13.97%	20.21%
$2.82	$2.76	$2.66	$2.56	$2.44	$2.32	$2.32
$38.500	$39.500	$45.875	$42.000	$39.125	$34.125	$34.250
$29.500	$29.000	$38.500	$34.125	$30.000	$26.875	$24.750
$37.375	$29.500	$40.250	$41.500	$39.000	$31.125	$34.250
$120,033	$94,807	$104,547	$109,020	$73,865	$39,189	$31,437
$59,363	$63,044	$94,743	$66,390	$63,157	$64,018	$77,041
1,890,575	1,892,955	1,844,041	1,799,456	1,851,447	1,826,700	1,883,363
2,273,965	2,285,942 (2)	2,359,023	2,303,216 (2)	2,347,757	2,259,340	2,254,099
1,126,458	1,135,831 (2)	1,036,547	997,168 (2)	980,071	1,060,751	1,109,119
48,435	48,718	50,715	52,984	55,118	58,013	60,427
5,339,433	5,363,446	5,290,326	5,152,824	5,234,393	5,204,804	5,307,008
278,326	275,441	273,752	273,936	274,064	275,637	276,385
28,550	28,394 (2)	28,968	28,848 (2)	29,768	29,808	29,526
1,599	1,538 (2)	959	1,017 (2)	268	319	347
1,122	1,127	1,175	1,358	1,361	1,352	1,316
309,597	306,500	304,854	305,159	305,461	307,116	307,574
13.79	13.33	12.92	12.58	12.25	11.60	10.89
11.42	10.97	10.88	11.00	10.89	10.39	9.75
9.50	9.18	9.40	9.73	9.38	8.91	8.37
8.53	8.69	8.89	8.84	8.64	8.06	7.58
5,647,690	5,652,657	5,630,581	5,475,664	5,541,477	5,501,495	5,603,502
1,156,740	1,130,780	1,114,900	1,034,440	1,145,820	1,054,600	1,094,400
1,434,102	1,462,290	1,515,420	1,402,800	1,474,190	1,449,600	1,289,800
55.74%	57.07%	57.65%	60.26%	55.21%	59.55%	58.45%
37	35	31	34	34	43	39
7	14	16	17	21	24	37
37	32	38	35	29	20	11
9	9	8	8	9	9	9
5	4	1	1	4	3	3
5	6	6	5	3	1	1
$637,219	$619,097	$605,887	$608,176	$607,997	$589,346	$577,611
1,889	(229)	(2,328)	(41,221)	(37,497)	(45,900)	(49,778)
0	0	0	21,031	14,814	8,211	0
$639,108	$618,868	$603,559	$587,986	$585,314	$551,657	$527,833
11.93	11.54	11.45	11.80	11.62	11.32	10.88
0.04	0.00	(0.04)	(0.80)	(0.72)	(0.88)	(0.93)
0.00	0.00	0.00	0.41	0.28	0.16	0.00
11.97	11.54	11.41	11.41	11.18	10.60	9.95
1.71	1.76	1.75	2.43	2.67	2.63	2.78
2.22	2.14	2.08	2.98	3.11	2.89	2.98
0.85	0.94	1.23	1.42	1.62	1.55	0.89
1,358	1,377	1,490	1,554	1,571	1,587	1,627
$72,984	$75,441	$75,305	$74,052	$71,888	$69,237	$65,175

(2) Includes reclassification of certain Commercial and Industrial customers.

C

EXECUTIVE OFFICERS

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President and Chief Executive Officer

ROBERT L. FISCUS
Vice Chairman of the Board of Directors
and Chief Financial Officer

JAMES F. CROWE
Group Vice President Power Supply Services

ALBERT N. HENRICKSEN
Group Vice President Support Services

ANTHONY J. VALLILLO
Group Vice President Client Services

RITA L. BOWLBY
Vice President Corporate Affairs

STEPHEN F. GOLDSCHMIDT
Vice President Planning and Information Resources

JAMES L. BENJAMIN
Controller

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CHARLES J. PEPE
Assistant Treasurer and Assistant Secretary

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Associate Dean
Yale Law School

NATHANIEL D. WOODSON
Chairman of the Board of Directors
President and Chief Executive Officer
The United Illuminating Company

INVESTOR INFORMATION

Transfer, Registrar and Dividend Disbursing Agent

AMERICAN STOCK TRANSFER & TRUST COMPANY
Telephone Inquiries:
(800) 937.5449 or (718) 921.8200
Email Address:
info@amstock.com
Website Address:
http://www.amstock.com

Address Shareowners Inquiries to

AMERICAN STOCK TRANSFER & TRUST COMPANY
40 Wall Street, 46th Floor
New York, NY 10005

Send Certificates for Transfer and Address Changes to

AMERICAN STOCK TRANSFER & TRUST COMPANY
40 Wall Street, 46th Floor
New York, NY 10005

Annual Meeting Date

The Company's Annual Meeting will be held at:

THE NEW HAVEN LAWN CLUB
193 Whitney Avenue
New Haven, CT
on Wednesday, May 19, 1999
beginning at 1:00 p.m.

Dividend Reinvestment Plan

Common Stock shareowners of record interested in obtaining information regarding the benefits of participating in UI's dividend reinvestment plan may write to:

AMERICAN STOCK TRANSFER & TRUST COMPANY
40 Wall Street, 46th Floor
New York, NY 10005

Investor Relations Hotline

For information on UI's earnings, news releases, media articles and dividend information, including ex-dividend dates and dividend payment dates, call:

From within the New Haven area:
(203) 499.3333 or

From outside the New Haven area:
(800) 7.CALL UI (722.5584)

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WIGGIN & DANA

Stock Listing

NEW YORK STOCK EXCHANGE; COMMON STOCK (UIL)

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MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

FINANCIAL STATEMENTS WITH SUPPLEMENTARY INFORMATION

DECEMBER 31, 1998, 1997 AND 1996 WITH INDEPENDENT AUDITORS' REPORT THEREON

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
FINANCIAL STATEMENTS WITH SUPPLEMENTARY INFORMATION
DECEMBER 31, 1998, 1997 AND 1996

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KPMG Peat Marwick LLP

99 High Street
Boston, MA 02110-2371

Telephone 617 988 1000

Telefax 617 988 0800

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, 1998, 1997 and 1996 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, 1998, 1997 and 1996, 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 LLP

March 5, 1999

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
STATEMENTS OF FINANCIAL POSITION
DECEMBER 31, 1998, 1997 AND 1996
(In Thousands)

ASSETS	1998	1997	1996
Electric Plant			
In Service (Note 4)	$ 1,241,237	$ 1,239,161	$ 1,237,306
Accumulated Depreciation	(456,650)	(414,028)	(371,762)
	784,587	825,133	865,544
Nuclear Fuel - Net of Amortization	12,164	11,452	13,500
Total Electric Plant	796,751	836,585	879,044
Special Funds (Notes 2, 3 and 5)	239,547	226,141	223,702
Current Assets			
Cash and Temporary Investments (Note 5)	1,718	1,307	1,390
Accounts Receivable	6,678	9,234	6,213
Unbilled Revenues (Note 2)	3,776	5,593	6,620
Inventories (Note 2)	13,747	14,463	13,873
Prepaid Expenses	8,488	7,023	12,393
Total Current Assets	34,407	37,620	40,489
Total Special Funds and Current Assets	273,954	263,761	264,191
Deferred Charges			
Amounts Recoverable Under Terms of the Power Sales Agreements (Note 2)	223,670	208,314	212,853
Unamortized Debt Discount and Expenses	24,815	27,147	29,865
Nuclear Decommissioning Trusts	14,713	12,072	9,676
Other	3,241	3,340	4,473
	266,439	250,873	256,867
	$ 1,337,144	$ 1,351,219	$ 1,400,102
LIABILITIES			
Long-Term Debt			
Bonds Payable (Note 3)	$ 1,178,085	$ 1,222,735	$ 1,264,050
Current Liabilities			
Current Maturities of Long-Term Debt (Note 3)	44,650	41,315	39,415
Commercial Paper (Note 3)	21,205	-	-
Accounts Payable	7,514	12,241	16,068
Accrued Expenses	17,696	14,712	14,623
Member and Participant Advances and Reserves	52,538	47,302	55,338
	143,603	115,570	125,444
Deferred Credits	15,456	12,914	10,608
Commitments and Contingencies (Note 9)			
	$ 1,337,144	$ 1,351,219	$ 1,400,102

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

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 1998, 1997 AND 1996
(In Thousands)

	1998	1997	1996
Revenues (Note 2)	$ 227,949	$ 242,502	$ 211,217
Interest Income	15,286	14,553	14,494
Total Revenues and Interest Income	$ 243,235	$ 257,055	$ 225,711
Operating and Service Expenses:			
Fuel Used in Electric Generation	$ 27,530	$ 27,824	$ 16,997
Purchased Power	41,754	45,421	45,389
Other Operating	35,028	36,796	30,660
Maintenance	12,108	19,206	11,645
Depreciation	44,837	44,699	44,607
Taxes Other Than Income	5,652	6,298	6,443
	166,909	180,244	155,741
Interest Expense:			
Interest Charges	70,711	72,854	74,470
Interest Charged to Projects During Construction (Note 2)	(95)	(45)	(62)
	70,616	72,809	74,408
Total Operating Costs and Interest Expense	237,525	253,053	230,149
Other (Note 7)	22,000	-	(6,737)
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements (Note 2)	(16,290)	4,002	2,299
	$ 243,235	$ 257,055	$ 225,711

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

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 1998, 1997 AND 1996
(In Thousands)

	1998	1997	1996
Cash flows from operating activities:			
Total Revenues and Interest Income	$ 243,235	$ 257,055	$ 225,711
Total Costs and Expenses, net	(259,525)	(253,053)	(223,412)
Adjustments to arrive at net cash provided by operating activities:			
Depreciation and Decommissioning	46,609	46,405	45,977
Amortization	6,635	6,693	7,956
Change in current assets and liabilities:			
Accounts Receivable	2,556	(3,021)	1,831
Unbilled Revenues	1,817	1,027	(1,059)
Inventories	716	(590)	(58)
Prepaid Expenses	(1,465)	5,370	(6,375)
Accounts Payable	(4,727)	(3,827)	7,446
Accrued Expenses and Other	2,990	687	5,855
Member and Participant Advances and Reserves	5,236	(8,036)	6,337
Net cash provided by operating activities	44,077	48,710	70,209
Cash flows from investing activities:			
Construction Expenditures and Purchases of Nuclear Fuel	(9,134)	(6,363)	(7,673)
Interest Charged to Projects During Construction	(95)	(45)	(62)
Net Increase in Special Funds	(13,406)	(2,439)	(21,606)
Change in net Unrealized Gain (Loss) on Special Funds	934	537	(1,579)
Decommissioning Trust Payments, net	(2,641)	(2,396)	(1,913)
Other	1,062	1,328	505
Net cash used for investing activities	(23,280)	(9,378)	(32,328)
Cash flows from financing activities:			
Payments for Principal of Long-Term Debt and Commercial Paper	(42,610)	(39,415)	(37,750)
Proceeds from Commercial Paper	22,500	-	-
Payments for Commercial Paper Issue Costs	(276)	-	-
Net cash used for financing activities	(20,386)	(39,415)	(37,750)
Net increase (decrease) in cash and temporary investments	411	(83)	131
Cash and Temporary Investments at Beginning of Year	1,307	1,390	1,259
Cash and Temporary Investments at End of Year	$ 1,718	$ 1,307	$ 1,390
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 67,714	$ 69,854	$ 71,313

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

MASSACHUSETTS MUNICIPAL WHOLESALE
ELECTRIC COMPANY
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 1998, 1997 AND 1996

(1) Nature of Operations

The Massachusetts Municipal Wholesale Electric Company (MMWEC) is a public corporation and a political subdivision of the Commonwealth of Massachusetts formed to be a joint action agency and to develop a bulk power supply for its member Massachusetts municipal electric systems and other utilities. MMWEC is authorized to construct, own, or purchase ownership interests in, and to issue revenue bonds to finance, electric facilities (Projects) secured by MMWEC's revenues derived from Power Sales Agreements (PSAs) with its members and other utilities. The power supply program consists of power purchase arrangements, power brokering services, planning and financial services, and the Projects relating to generating facilities built and operated by MMWEC and other regional utilities.

A Massachusetts city or town having a municipal electric system, authorized by majority vote of the city or town, may become a member of MMWEC by applying for admission and agreeing to comply with the terms and conditions of membership as the MMWEC By-Laws may require. As of December 31, 1998, twenty-five Massachusetts municipal electric systems were members. Termination of membership does not relieve a system of its PSA obligations.

(2) Significant Accounting Policies

MMWEC presents its financial statements in accordance with generally accepted accounting principles as promulgated by the Financial Accounting Standards Board which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Interest Charged to Projects During Construction

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

(2) Significant Accounting Policies (continued)

Nuclear Fuel

Nuclear fuel, net of amortization, includes MMWEC's ownership interest of fuel in use, in stock and in process for Millstone Unit 3 and Seabrook Station. The cost of nuclear fuel is amortized to Fuel Used in Electric Generation based on the relationship of energy produced in the current period to total expected energy production for fuel in the reactor. A provision for fuel disposal costs is included in Fuel Used in Electric Generation based upon disposal contracts with the Department of Energy (DOE). In addition, Fuel Used in Electric Generation includes the annual assessment, under the Energy Policy Act of 1992, for the cost of decontamination and decommissioning of uranium enrichment plants operated by the DOE. Billings from the DOE will occur over the next nine years. At December 31, 1998, MMWEC's share of Millstone Unit 3 and Seabrook Station unbilled assessments was $361,000 and $548,000, respectively. The amounts are included in Other Deferred Charges and Deferred Credits on the Statements of Financial Position.

Special Funds

The Special Funds, other than certain Working Capital Funds, are invested in accordance with the General Bond Resolution (GBR). The composition of Special Funds is as follows:

Fund	1998	1997	1996
		(In Thousands)	
Bond Fund Interest, Principal and Retirement Account to pay principal and interest on bonds	$ 43,742	$ 37,507	$ 30,636
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	80,216	79,942	79,740
Reserve and Contingency Fund to make up deficiencies in the Bond Fund and pay for renewals and extraordinary costs	22,840	21,559	19,748
Revenue Fund to receive revenues and disburse them to other funds	66,842	67,669	73,616
Working Capital Funds to maintain funds to cover operating expenses	25,907	19,464	19,962
Total Special Funds	$239,547	$226,141	$223,702

(2) Significant Accounting Policies (continued)

Cash and Temporary Investments

Certain cash and temporary investment amounts used for power purchases and working capital requirements of MMWEC are not subject to the provisions of the GBR. In addition to the investment securities delineated in the GBR, MMWEC invests in repurchase agreements with banks where MMWEC has established accounts.

Revenues and Unbilled Revenues

Revenues include electric sales for resale provided under MMWEC's power supply program which consists of billings under the PSAs, Power Purchase Agreements and related power brokering arrangements. MMWEC provides its members with power supply planning and related services which are billed as Service Revenues. Amounts which are not yet billed are included in Unbilled Revenues on the Statements of Financial Position. Revenues are comprised of the following:

Revenues	1998	1997	1996
		(In Thousands)	
Electric sales for resale	$225,690	$237,795	$207,414
Service	1,426	1,653	1,803
PSNH Settlement	833	2,000	2,000
Gain on land taken by eminent domain	-	1,054	-
Total Revenues	$227,949	$242,502	$211,217

Inventories

Fuel oil and spare parts inventory are recorded and accounted for by the average cost method. At December 31, 1998, 1997 and 1996, fuel oil inventory was valued at $4.9, $4.7 and $4.4 million, and spare parts inventory amounted to $8.8, $9.8 and $9.5 million, respectively.

Amounts Recoverable Under Terms of the Power Sales Agreements

Billings to Project Participants are designed to recover costs in accordance with the PSAs. The billings are 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 canceled Projects, cost of refunding, billing for certain interest, reserves, net unrealized gain or loss on securities available for sale and other costs. Individual Projects have a cumulative deferral of costs which total $228.8, $212.9 and $217.1 million and have cumulative billings in excess of costs which total $5.1, $4.6 and $4.2 million at December 31, 1998, 1997 and 1996, respectively. These amounts have been netted in the Statements of Financial Position.

(2) Significant Accounting Policies (continued)

Amounts Recoverable Under Terms of the Power Sales Agreements (continued)

The December 31, 1998, 1997 and 1996 balances of $223.7, $208.3 and $212.9 million, respectively, reflects the Statements of Operations net decrease (increase) of ($16.3), $4.0 and $2.3 million for the years then ended and the change in net unrealized gain (loss) on securities available for sale of $.9, $.6 and ($1.6) million for 1998, 1997 and 1996, respectively.

Nuclear Decommissioning Trusts

MMWEC maintains external trust funds, as promulgated by Nuclear Regulatory Commission and state regulations, to provide for the decommissioning activities of Millstone Unit 3 and Seabrook Station. The December 31, 1998 Millstone Unit 3 and Seabrook Station balances of $6.9 and $7.8 million, respectively, are stated at cost and are included as part of the Deferred Charges and Deferred Credits on the Statements of Financial Position. MMWEC's share of the estimated reserve requirement for the prompt dismantling and removal of the Millstone Unit 3 and Seabrook Station, at the expiration of their original operating licenses in 2025 and 2026, is $28 and $58 million, respectively.

Depreciation

Electric plant in service is depreciated using the straight-line method. The aggregate annual provisions for depreciation for 1998, 1997 and 1996 averaged 4% of the original cost of depreciable property.

Interest Rate Protection Agreement

Premiums paid for the purchase of an Interest Rate Protection Agreement are amortized to interest expense over the term of the agreement. Unamortized premiums are included in Other Deferred Charges in the Statements of Financial Position.

(3) Debt

Power Supply System Revenue Bonds

MMWEC financings, other than obligations maturing within one year, require Massachusetts Department of Telecommunications and Energy's authorization. To finance the ownership interests in electric generating facilities under its GBR, MMWEC issued Power Supply System Revenue Bonds (Bonds). The Bonds are secured under the GBR by a 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.

(3) Debt (continued)

Power Supply System Revenue Bonds (continued)

Bonds Payable consists of serial, term and variable-rate bonds and are comprised of the following issues.

Issue	Net Interest Cost	December 31, 1998	1997	1996
			(In Thousands)	
1987 Series A	8.9%	$ 7,850	$ 8,525	$ 9,150
1992 Series A	7.0%	92,285	94,625	96,825
1992 Series B	7.0%	180,495	186,170	191,525
1992 Series C	6.9%	55,740	57,095	58,375
1992 Series D	6.3%	77,990	80,460	82,805
1992 Series E	6.0%	84,615	92,865	100,715
1993 Series A	5.3%	343,390	356,030	367,980
1993 Series B	5.9%	-	-	190
1994 Series A	5.3%	113,670	114,195	114,690
1994 Series B	5.1%	169,100	176,485	183,610
1994 Series C	Variable	97,600	97,600	97,600
Bonds Payable		1,222,735	1,264,050	1,303,465
Less: Current Maturities		(44,650)	(41,315)	(39,415)
Total Long-Term Debt		$1,178,085	$1,222,735	$1,264,050

The serial and term bonds are generally subject to optional redemption approximately ten years after the issue date, at 103% of the principal amount, descending periodically thereafter to 100%. The aggregate annual principal payments due on the bonds in the next five years are as follows: 1999 - $44,650,000; 2000 - $47,870,000; 2001 - $50,580,000; 2002 - $53,370,000 and 2003 - $56,635,000.

The interest rates on the 1994 Series C variable-rate bonds are adjusted from time-to-time. Bondholders may require repurchase of the 1994 Series C bonds at the time of such interest rate adjustment. In 1997, MMWEC substituted the 1994 Series C bonds letter of credit facility with an insurance policy guaranteeing the payment of the principal and interest on the 1994 Series C Bonds and a liquidity facility with a bank providing for the purchase, by the bank, of the 1994 Series C bonds if the bonds cannot be remarketed. The debt service on the 1994 Series C bonds is on a parity with the senior lien fixed-rate bonds to the extent that the debt service on the 1994 Series C bonds is equal to or less than the debt service on the bonds refunded by the 1994 Series C bonds in a given bond year.

(3) Debt (continued)

Debt Service Forward Delivery Agreement

In conjunction with the issuance of the 1994 Series C bonds, MMWEC entered into a seven year Debt Service Forward Delivery Agreement (Forward Agreement) for purposes other than trading. MMWEC makes monthly deposits to the various accounts within the Bond Fund for the semiannual payment of its debt service on its outstanding bonds. In exchange for the right to direct the investment of such monies, the counterparty pays a fixed amount to MMWEC on a periodic basis, providing MMWEC a fixed yield that could be earned on a security with a five to seven year maturity purchased at the time the contract was executed, while complying with the maturity limitations for investments in the Bond Fund under the terms of the GBR. The counterparty has the right to sell to MMWEC Government Obligations that mature prior to the relevant debt service payment dates during the term of the Forward Agreement.

MMWEC reserves the right to terminate the Forward Agreement in whole or in part in connection with any purchase, redemption or refunding of fixed-rate bonds, counterparty default or counterparty credit rating deterioration to below investment grade. The Forward Agreement provides for the calculation and payment of liquidated damages to the counterparty reflecting market interest rates at the time of the termination compared to the rate levels in the Forward Agreement.

The cash requirement under the Forward Agreement requires MMWEC to make available to the counterparty an average balance of $30.3 million over the seven year term of the agreement in exchange for investments in Government Securities, to be held by MMWEC's trustee, that mature prior to MMWEC's debt payment dates.

The Forward Agreement is not recognized in the Statements of Financial Position to the extent that settlement of cash in exchange for financial instruments has not occurred. To the extent cash has been exchanged for Government Securities, the Government Securities are recorded on the Statements of Financial Position as Special Funds.

Interest Rate Protection Agreement

The 1994 Series C bonds provide a hedge against interest rate risk on the net funding cost of approximately $100 million of short-term floating rate investment assets. MMWEC purchased a $41 million Interest Rate Protection Agreement (Cap Agreement), comprised of an $11 million tranche with a protection rate of 6.85% expiring on June 30, 2000, and a $30 million tranche with a protection rate of 7.25% expiring on June 30, 2002, to limit the interest rate exposure on a portion of the 1994 Series C variable-rate debt to the extent that the variable debt costs exceed the fixed-rate received on the Forward Agreement described above.

(3) Debt (continued)

Interest Rate Protection Agreement (continued)

MMWEC purchased the right to receive annually an amount by which an index-based interest rate, which approximates the interest rate on the 1994 Series C bonds, exceeds the protection rate in the Cap Agreement. MMWEC has the right to terminate the Cap Agreement if the provider or its guarantor's credit rating falls below a double A and receive payment of liquidation damages designed to enable MMWEC to enter into an equivalent agreement. The cost of the Cap Agreement was paid up front and is included in Other Deferred Charges on the Statements of Financial Position. There are no future MMWEC cash requirements under the terms of the Cap Agreement. The Cap Agreement was purchased for purposes other than trading.

Net Revenue Available for Debt Service

In accordance with the provisions of MMWEC's GBR, MMWEC covenants that it shall fix, revise and collect rates, tolls, rents and other fees and charges, sufficient to produce revenues to pay all operating and maintenance expenses and principal of, premium, if any, and the interest on the Bonds and to pay all other obligations against its revenue. Revenues, which include applicable interest earnings from investments, are required to equal 1.10 times the annual debt service for each contract year ending June 30, after deduction of certain operating and maintenance expenses and exclusive of depreciation. For the contract years ended June 30, 1998, 1997, 1996 and prior years, MMWEC met the GBR debt service coverage requirements for the applicable MMWEC Projects.

	Contract Year Ended June 30,		
	1998	1997	1996
Debt Service Coverage:		(In Thousands)	
Revenues	$191,245	$171,378	$161,324
Other Billings	576	576	576
Reserve and Contingency Fund Billings	11,626	11,159	10,972
Total	203,447	183,113	172,872
Less: Operating & Maintenance Expenses	(75,566)	(60,371)	(52,184)
Available Revenues Net of Expenses	$127,881	$122,742	$120,688
Debt Service Requirement	$116,255	$111,583	$109,716
Coverage (110% Required)	110%	110%	110%

Notes Payable

MMWEC maintains a $5 million revolving line of credit to temporarily finance certain power purchases made by MMWEC for resale under power purchase contracts. There were no borrowings outstanding under the line of credit at December 31, 1998, 1997 and 1996. During 1998, 1997 and 1996 the maximum outstanding balance under the line of credit was $90,000, $167,600 and $4,000, respectively. Interest charged on borrowings under the line of credit is at the bank's prime rate of 7.75% at December 31, 1998. In addition, a commitment fee of one quarter of 1% per annum is charged on the unused portion of the line based on the average daily principal amount of the loan outstanding.

(3) Debt (continued)

Commercial Paper

In June 1998, MMWEC issued $22.5 million of 1998 Series A Notes under the Power Purchase Commercial Paper Note Resolution (Resolution). MMWEC is permitted to issue commercial paper notes maturing not more than 270 days from the date of issuance up to a maximum of $22.5 million. The Series A Notes are not subject to redemption prior to maturity but are subject to acceleration upon the occurrence of an Event of Default under the Resolution. The Series A Notes are a special obligation of MMWEC payable solely from the revenues and other monies specified in the Resolution. In addition, a five-year bank letter of credit in the amount of $23 million at December 31, 1998 to the Issuing Agent provides security for the payment of principal and interest on the Series A Notes. The balance outstanding at December 31, 1998 of commercial paper notes was $21.2 million at an interest rate of 3.2%.

(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 Unit No. 4, Millstone Unit 3 and Seabrook Station units. Electric Plant In Service also includes MMWEC's Service Operations which totalled $2.5, $2.7 and $2.6 million in 1998, 1997 and 1996, respectively. The following is a summary of Projects included in electric plant in service and MMWEC's share of capability.

Projects	Facility and MMWEC Share of Capability (MW)		Amounts as of December 31, 1998	1997	1996
			(In Thousands)		
Peaking Project	Stony Brook	170.0	$ 56,338	$ 56,310	$ 56,588
Intermediate Project	Stony Brook	311.3	153,968	152,786	151,363
Wyman Project	W.F.Wyman No. 4	22.7	7,365	7,361	7,359
Nuclear Project No. 3	Millstone Unit 3	36.8	129,814	129,595	129,296
Nuclear Mix No. 1	Millstone Unit 3	18.4	51,400	51,290	51,140
Nuclear Mix No. 1	Seabrook Station	1.9	8,599	8,589	8,587
Nuclear Project No. 4	Seabrook Station	49.8	259,204	258,925	258,882
Nuclear Project No. 5	Seabrook Station	12.6	70,930	70,859	70,849
Project No. 6	Seabrook Station	69.0	501,098	500,712	500,652
			$1,238,716	$1,236,427	$1,234,716

(4) Electric Generation Facilities and Financing (continued)

In 1997, the Nuclear Regulatory Commission (NRC) issued a rulemaking indicating that it may deem it necessary to promulgate rules making joint owners of nuclear power plants jointly and severally liable for decommissioning costs. In addition, several bills have been introduced in the New Hampshire Legislature, the effect of which would accelerate decommissioning payments for Seabrook Station and make the Seabrook Station joint owners jointly and severally liable for decommissioning costs. No such statute has been enacted to date.

(5) Investments and Deposits

All bank deposits, which amounted to $431,000 at December 31, 1998, are maintained at one financial institution. The Federal Deposit Insurance Corporation currently insures up to $100,000 per depositor. MMWEC's uninsured deposits totaled as much as $4.5 million during 1998 due to seasonal cash flows, and the timing of daily cash receipts. At December 31, 1998, 1997 and 1996 investments are classified as available for sale and reported at fair value with unrealized gains of $2.7, $1.8 and $1.4 million, respectively, and unrealized losses of $47,000, $76,000 and $235,000 excluded from earnings and reported as a component of Amounts Recoverable Under the Terms of the Power Sales Agreement on the Statements of Financial Position. At December 31, 1998, all securities underlying repurchase agreements, and all other investments, were held in MMWEC's name by 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:

	1998		1997		1996	
Type of Investment	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value	Amortized Cost Basis	Market Value
			(In Thousands)			
Repurchase Agreements	$ -	$ -	$ 1,523	$ 1,573	$ -	$ -
Other Investments:						
U.S. Treasury bills	20,825	21,524	19,215	19,799	18,420	18,917
U.S. Treasury notes	79,077	80,866	83,141	84,049	65,727	66,214
Municipal bonds	7,089	7,276	7,159	7,381	7,252	7,469
U.S. Agency discount notes	133,010	133,000	114,086	114,053	133,054	133,047
Total Other Investments	240,001	242,666	223,601	225,282	224,453	225,647
Total Investments	$240,001	$242,666	$225,124	$226,855	$224,453	$225,647

(5) Investments and Deposits (continued)

During 1998, 1997 and 1996, the proceeds from the sale of available for sale securities were $0, $.5 and $.3 million resulting in gross realized gains of $0, $0 and $37 and gross realized losses of $0, $67 and $0, respectively. The basis on which cost was determined in computing realized gain or loss was specific identification. Including repurchase agreements, the average contractual maturity of the investments in debt securities at December 31, 1998, 1997 and 1996 were 347, 393 and 345 days, respectively.

Due to seasonal cash flows during 1998, 1997 and 1996, 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. Market values of the securities are based on independent quoted market prices.

(6) Fair Values of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value:

Investments and Decommissioning Trusts - The fair values estimated are based on quoted market prices for those or similar investments.

Long-Term Debt - The fair value is estimated based on quoted market prices for the same or similar issues.

Interest Rate Protection Agreement - The fair value is based on average quoted market prices of agreements with similar duration and strike prices.

Debt Service Forward Delivery Agreement - The fair value generally reflects the estimated amounts that MMWEC would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current unrealized gains or losses of open contracts.

The estimated fair values of MMWEC's financial instruments are as follows:

(6) Fair Values of Financial Instruments (continued)

	1998		1997		1996	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
			(In Thousands)			
Financial Assets:						
Investments	$ 242,666	$ 242,666	$ 226,855	$ 226,855	$ 225,647	$ 225,647
Decommissioning Trusts	14,713	17,310	12,072	13,290	9,676	9,837
Interest Rate Protection Agreement	263	75	375	178	486	275
Financial Liabilities:						
Long-Term Debt	1,178,085	1,229,525	1,222,735	1,262,465	1,264,050	1,270,771
Unrecognized Financial Instruments:						
Debt Service Forward Delivery Agreement	-	3,070	-	3,313	-	3,326

The carrying amounts for Cash, Accounts Receivable, Notes Payable, Accounts Payable and Accrued Expenses approximate their fair value due to the short-term nature of these instruments.

(7) Other Charges and Credits to Income

In June 1998, MMWEC negotiated the payment of $22 million, which was financed through the issuance of $22.5 million in commercial paper notes, for the buy-out and termination of an uneconomic Power Purchase Contract under which MMWEC had agreed to purchase electric capacity and output for resale to certain cities and towns of the Commonwealth having municipal electric departments.

During 1996, MMWEC recorded a gain of $6.7 million in connection with the sale of equipment from Seabrook Unit 2.

(8) 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.

(8) Benefit Plans (continued)

The Pension Benefit Obligation was determined by an actuarial valuation performed as of January 1 of each of the years presented. Significant actuarial assumptions used in the valuation include a weighted-average discount rate of 7.0% in 1998 and 7.5% in 1997 and 1996 and projected salary increases of 4.0% in 1998 and 5.5% in 1997 and 1996. The Pension Benefit Obligation for both plans is as follows:

	Amounts as of January 1,		
	1998	1997	1996
		(In Thousands)	
Retirees currently receiving benefits and terminated employees not yet receiving benefits	$ 582	$ 384	$ 299
Current Employees:			
Vested	3,891	3,295	2,677
Non-vested	2,775	3,081	2,602
Total Pension Benefit Obligation	7,248	6,760	5,578
Net assets available for benefits, at market	7,264	5,898	4,850
Under (Over) funded Pension Benefit Obligation	$ (16)	$ 862	$ 728

MMWEC makes annual contributions to the pension plans equal to the amounts recorded as pension expense, which were $498,000, $896,000 and $557,000, for the years ended December 31, 1998, 1997 and 1996, 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 8.5%. Pension costs applicable to prior years' service are amortized over thirty years.

MMWEC contributes to an employee savings plan administered by an insurance company. All full-time employees meeting the service requirements are eligible to participate in this defined contribution plan. Under the provisions of the plan, MMWEC's contributions vest immediately. MMWEC contributed $99,000, $114,000 and $107,000 while the employees contributed $169,000, $184,000 and $175,000 during the years ended December 31, 1998, 1997 and 1996, respectively.

(9) Commitments and Contingencies

Power Purchases

MMWEC entered into agreements for participation in the transmission interconnection between New England utilities and the Hydro-Quebec electric system near Sherbrooke, Quebec (Phase I), which began commercial operation in October 1986. The New England portion of the interconnection was constructed at a total cost of about $140 million, of which 3.65% or $5 million is MMWEC's share to

(9) Commitments and Contingencies (continued)

Power Purchases (continued)

support. MMWEC also entered into similar agreements for participation in the interconnection between New England utilities and the Hydro-Quebec electric system for the expansion of the Hydro-Quebec interconnection (Phase II), which went into commercial operation in November 1990. MMWEC's Phase II equity investment approximates 0.6% or $3.3 million. MMWEC has corresponding agreements with certain of its members and another utility to recover MMWEC's share of the costs associated with the interconnection.

Power Sales Agreements

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

In 1988, the Vermont Supreme Court ruled that the Project No. 6 PSAs between MMWEC and the Vermont Project Participants were void since inception. Consequently, pursuant to the PSAs, MMWEC increased the remaining Project No. 6 Participants pro rata shares of Project Capability to cover the shortfall (step-up), which action was challenged by certain Massachusetts Participants. The Supreme Judicial Court (SJC) for the Commonwealth of Massachusetts in MMWEC et. al. v. Town of Danvers et. al. noted that "the Project 6 PSAs executed by the defendants are valid and that the step-up provisions therein have been properly invoked".

MMWEC is involved in various legal actions. Based on bond counsels' opinions regarding the validity of the PSAs and general counsel representations regarding the litigation, discussions with such counsel, and other considerations, management believes that the ultimate resolution of such litigation will not have a material, adverse effect on the financial position of MMWEC.

In November 1997, the Commonwealth of Massachusetts enacted legislation to restructure the electric utility industry. MMWEC and the municipal light departments are not specifically subjected to the legislation. However, it is management's belief that industry restructuring and customer choice, promulgated within the legislation, will have an effect on MMWEC and the Participant's operations.

MMWEC performed an extensive study of the potential effects of restructuring of the electric utility industry on MMWEC, and in February 1997, the Board of Directors adopted an amendment to the General Bond Resolution permitting MMWEC to collect funds from the Project Participants for purposes of utilizing those funds to mitigate the adverse consequences of competition. Six Project Participants sought a declaratory judgment and an injunction on whether the MMWEC Board of Directors has the authority to adopt the amendment. The court denied the injunction and the issue has been referred to arbitration.

(9) Commitments and Contingencies (continued)

Other Issues

The Price-Anderson Act (the Act), a federal statute amended in 1988 to extend to the year 2002, mandates an industry-wide program of liability insurance for nuclear facilities. The Act now provides approximately $9.6 billion for public liability claims from a single incident at a nuclear facility. The $200 million primary layer of insurance for the liability has been purchased in the commercial market. Secondary coverage of $9.4 billion is to be provided through a $83.9 million per incident assessment of each of the currently licensed nuclear units in the United States. The maximum assessment is $10 million per incident per unit in any year. The maximum assessment is subject to adjustment for inflation every five years. MMWEC's interest in Millstone Unit 3 and Seabrook Station could result in a maximum assessment of $4.0 and $9.7 million, respectively.

Insurance has been purchased from Nuclear Electric Insurance Limited (NEIL) to cover the cost of repair, replacement, decontamination or premature decommissioning of utility property resulting from insured occurrences at Millstone Unit 3 and Seabrook Station. The system is subject to retroactive assessments if losses exceed the accumulated funds available to the insurer. MMWEC is potentially subject to a $.4 and $1.7 million assessment for its participation in Millstone Unit 3 and Seabrook Station, respectively, for excess property damage, decontamination and premature decommissioning.

MMWEC is not currently covered under gradual pollution liability insurance related to MMWEC's Stony Brook power plant. Nothing has come to management's attention concerning any material pollution liability claims made during 1998 or outstanding as of December 31, 1998.

MMWEC has established a trust fund to enhance its Directors' and Officers' liability coverage. The purpose of the fund is to make available funds for the purchase of Directors' and Officers' liability insurance or indemnification of the Directors or Officers.

(10) Year 2000 (Unaudited)

In 1998, MMWEC initiated a comprehensive plan (Plan) to identify, assess and remediate "Year 2000" issues within each of its significant computer hardware and software systems and certain equipment containing micro-processors. The Plan is addressing the issue of computer systems and embedded computer chips that may be unable to distinguish between the year 1900 and the year 2000 at the change of the millennium. MMWEC has divided the Plan into five major phases – inventory, assessment, remediation, testing and validation and contingency planning. MMWEC has completed the assessment and planning phases and is currently in the remediation, implementation and testing phases. Computer systems and equipment that are not Year 2000 ready are being replaced or reprogrammed. After remediation of Year 2000 issues is completed, Year 2000 readiness will be tested with any further problems being addressed through further remediation or contingency planning. The Plan anticipates Year 2000 readiness by third quarter 1999.

(10) Year 2000 (Unaudited) (continued)

MMWEC is in the process of identifying and contacting critical third party vendors and contractors regarding their plans and progress in addressing their Year 2000 issues. Electronic data interchanges with third parties are also being reviewed for Year 2000 readiness. MMWEC has received varying information from such third parties on the state of readiness or expected readiness. Contingency plans are being developed by MMWEC to mitigate Year 2000 induced operational vulnerabilities.

Failure to correct a material Year 2000 problem could result in an interruption in, or a failure of, certain normal business activities or operations. If such a failure were to occur, it could materially and adversely affect MMWEC's operations, liquidity and financial condition.

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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, 1998, 1997 and 1996.

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

KPMG Peat Marwick LLP

March 5, 1999

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
PROJECT STATEMENTS OF FINANCIAL POSITION
DECEMBER 31, 1998
(In Thousands)

ASSETS	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTERMEDIATE	WYMAN	HYDRO QUEBEC PHASE II	TOTAL
Electric Plant											
In Service	$ 2,521	$ 59,999	$ 129,814	$ 259,204	$ 70,930	$ 501,098	$ 56,338	$ 153,968	$ 7,365	$ -	$ 1,241,237
Accumulated Depreciation	(2,133)	(21,779)	(49,266)	(74,972)	(20,592)	(146,976)	(35,974)	(100,621)	(4,337)	-	(456,650)
	388	38,220	80,548	184,232	50,338	354,122	20,364	53,347	3,028	-	784,587
Nuclear Fuel-Net of Amortization	-	898	1,520	3,649	929	5,168	-	-	-	-	12,164
Total Electric Plant	388	39,118	82,068	187,881	51,267	359,290	20,364	53,347	3,028	-	796,751
Special Funds											
Bond Fund											
Interest, Principal and Retirement Account	-	3,218	3,065	7,983	2,401	18,376	2,407	6,005	287	-	43,742
Reserve Account	-	6,979	11,571	14,441	4,515	33,580	2,487	6,353	290	-	80,216
Reserve and Contingency Fund	-	3,574	3,745	4,615	1,242	6,864	869	1,642	289	-	22,840
Revenue Fund	-	4,885	7,186	9,113	2,372	16,846	6,883	18,095	1,462	-	66,842
Working Capital Funds	25,928	-	-	-	-	-	-	-	-	(21)	25,907
	25,928	18,656	25,567	36,152	10,530	75,666	12,646	32,095	2,328	(21)	239,547
Current Assets											
Cash and Temporary Investments	1,717	-	-	1	-	2	-	-	-	(2)	1,718
Accounts Receivable	4,739	19	42	7	2	10	78	1,661	14	106	6,678
Unbilled Revenues	3,776	-	-	-	-	-	-	-	-	-	3,776
Inventories	-	58	-	1,541	390	2,135	2,222	7,237	164	-	13,747
Advances to (from) Projects	1,049	(188)	(334)	(43)	(14)	(74)	(29)	(360)	(7)	-	-
Prepaid Expenses	605	1,012	1,873	1,859	472	2,581	13	21	52	-	8,488
Total Current Assets	11,886	901	1,581	3,365	850	4,654	2,284	8,559	223	104	34,407
Total Special Funds and Current Assets	37,814	19,557	27,148	39,517	11,380	80,320	14,930	40,654	2,551	83	273,954
Deferred Charges											
Amounts Recoverable (Payable) Under Terms of the Power Sales Agreements	20,951	64,901	89,539	35	5,453	39,255	(3,816)	8,681	(550)	(779)	223,670
Unamortized Debt Discount and Expenses	249	2,012	3,220	5,123	2,002	10,872	179	1,162	(4)	-	24,815
Nuclear Decommissioning Trusts	-	2,418	4,603	2,916	738	4,038	-	-	-	-	14,713
Other	28	186	297	607	157	896	77	169	65	759	3,241
	21,228	69,517	97,659	8,681	8,350	55,061	(3,560)	10,012	(489)	(20)	266,439
	$ 59,430	$ 128,192	$ 206,875	$ 236,079	$ 70,997	$ 494,671	$ 31,734	$ 104,013	$ 5,090	$ 63	$ 1,337,144
LIABILITIES											
Long-Term Debt											
Bonds Payable	$ -	$ 116,290	$ 191,565	$ 219,180	$ 66,560	$ 463,795	$ 26,740	$ 89,765	$ 4,190	$ -	$ 1,178,085
Current Liabilities											
Current Maturities of Long-Term Debt	-	5,585	5,665	6,495	1,835	13,165	3,530	8,030	345	-	44,650
Commercial Paper	21,205	-	-	-	-	-	-	-	-	-	21,205
Accounts Payable	2,739	102	117	1,147	290	1,588	22	1,393	116	-	7,514
Accrued Expenses	5,562	1,594	2,612	2,933	692	3,774	49	444	36	-	17,696
Member and Participant Advances and Reserves	29,924	2,108	2,137	3,229	837	8,063	1,393	4,381	403	63	52,538
	59,430	9,389	10,531	13,804	3,654	26,590	4,994	14,248	900	63	143,603
Deferred Credits	-	2,513	4,779	3,095	783	4,286	-	-	-	-	15,456
	$ 59,430	$ 128,192	$ 206,875	$ 236,079	$ 70,997	$ 494,671	$ 31,734	$ 104,013	$ 5,090	$ 63	$ 1,337,144

Schedule I

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
PROJECT STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 1998
(In Thousands)

	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTERMEDIATE	WYMAN	HYDRO QUEBEC PHASE II	TOTAL
Revenues	$ 43,046	$ 16,106	$ 24,428	$ 29,019	$ 8,240	$ 55,583	$ 8,206	$ 40,796	$ 1,979	$ 546	$ 227,949
Interest Income	1,344	1,106	1,598	2,297	684	5,164	757	2,128	127	81	15,286
Total Revenues and Interest Income	$ 44,390	$ 17,212	$ 26,026	$ 31,316	$ 8,924	$ 60,747	$ 8,963	$ 42,924	$ 2,106	$ 627	$ 243,235
Operating and Service Expenses:											
Fuel Used in Electric Generation	$ -	$ 297	$ 470	$ 1,655	$ 422	$ 2,367	$ 1,693	$ 19,646	$ 980	$ -	$ 27,530
Purchased Power	41,163	-	-	-	-	-	-	-	-	591	41,754
Other Operating	1,680	3,666	6,695	5,859	1,520	9,178	1,282	4,832	316	-	35,028
Maintenance	20	1,250	2,364	1,700	431	2,355	432	3,439	117	-	12,108
Depreciation	23	1,949	4,113	9,376	2,563	18,061	2,262	6,259	231	-	44,837
Taxes Other Than Income	4	436	791	1,063	269	1,472	390	1,078	149	-	5,652
	42,890	7,598	14,433	19,653	5,205	33,433	6,059	35,254	1,793	591	166,909
Interest Expense:											
Interest Charges	456	6,109	10,552	12,764	4,016	29,819	1,690	5,096	209	-	70,711
Interest Charged to Projects During Construction	-	(2)	(4)	(30)	(9)	(50)	-	-	-	-	(95)
	456	6,107	10,548	12,734	4,007	29,769	1,690	5,096	209	-	70,616
Total Operating Costs and Interest Expense	43,346	13,705	24,981	32,387	9,212	63,202	7,749	40,350	2,002	591	237,525
Other	22,000	-	-	-	-	-	-	-	-	-	22,000
Decrease (Increase) in Amounts Recoverable Under the Power Sales Agreements	(20,956)	3,507	1,045	(1,071)	(288)	(2,455)	1,214	2,574	104	36	(16,290)
	$ 44,390	$ 17,212	$ 26,026	$ 31,316	$ 8,924	$ 60,747	$ 8,963	$ 42,924	$ 2,106	$ 627	$ 243,235

Schedule II

MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY
PROJECT STATEMENTS OF CASH FLOWS
YEAR ENDED DECEMBER 31, 1998
(In Thousands)

	SERVICE	NUCLEAR MIX 1	NUCLEAR PROJ. 3	NUCLEAR PROJ. 4	NUCLEAR PROJ. 5	PROJECT NO. 6	PEAKING	INTERMEDIATE	WYMAN	HYDRO QUEBEC PHASE II	TOTAL
Cash flows from operating activities:											
Total Revenues and Interest Income	$ 44,390	$ 17,212	$ 26,026	$ 31,316	$ 8,924	$ 60,747	$ 8,963	$ 42,924	$ 2,106	$ 627	$ 243,235
Total Costs and Expenses, net	(65,346)	(13,705)	(24,981)	(32,387)	(9,212)	(63,202)	(7,749)	(40,350)	(2,002)	(591)	(259,525)
Adjustments to arrive at net cash provided by operating activities:											
Depreciation and Decommissioning	23	2,170	4,521	9,829	2,678	18,689	2,252	6,216	231	-	46,609
Amortization	28	459	706	1,770	512	2,834	57	267	2	-	6,635
Change in current assets and liabilities:											
Accounts Receivable	687	1	(4)	8	2	11	58	1,399	385	9	2,556
Unbilled Revenues	1,817	-	-	-	-	-	-	-	-	-	1,817
Inventories	-	-	-	2	1	1	(33)	647	98	-	716
Prepaid Expenses	280	(287)	(541)	(343)	(88)	(481)	(7)	(8)	10	-	(1,465)
Accounts Payable	(1,403)	56	123	(449)	(116)	(788)	475	(2,416)	(188)	(21)	(4,727)
Accrued Expenses and Other	411	506	913	486	114	621	(44)	(1)	1	(17)	2,990
Member and Participant Advances and Reserves	5,178	2,018	1,977	1,551	514	(2,569)	(250)	(3,232)	55	(6)	5,236
Net cash provided by (used for) operating activities	(13,935)	8,430	8,740	11,783	3,329	15,863	3,722	5,446	698	1	44,077
Cash flows from investing activities:											
Construction Expenditures and Purchases of Nuclear Fuel	(244)	(395)	(600)	(2,489)	(630)	(3,447)	(28)	(1,297)	(4)	-	(9,134)
Interest Charged to Projects During Construction	-	(2)	(4)	(30)	(9)	(50)	-	-	-	-	(95)
Net (Increase) Decrease in Special Funds	(6,432)	(2,453)	(3,658)	(2,895)	(894)	289	(371)	3,377	(358)	(11)	(13,406)
Change in net Unrealized Gain (Loss) on Special Funds	(40)	26	84	269	64	431	37	64	(1)	-	934
Decommissioning Trust Payments	-	(337)	(625)	(637)	(161)	(881)	-	-	-	-	(2,641)
Other	145	111	208	183	46	254	-	115	-	-	1,062
Net cash provided by (used for) investing activities	(6,571)	(3,050)	(4,595)	(5,599)	(1,584)	(3,404)	(362)	2,259	(363)	(11)	(23,280)
Cash flows from financing activities:											
Payments for Principal of Long-Term Debt and Commercial Paper	(1,295)	(5,380)	(4,145)	(6,185)	(1,745)	(12,460)	(3,360)	(7,705)	(335)	-	(42,610)
Proceeds from Commercial Paper	22,500	-	-	-	-	-	-	-	-	-	22,500
Payments for Commercial Paper Issue Costs	(276)	-	-	-	-	-	-	-	-	-	(276)
Net cash provided by (used for) financing activities	20,929	(5,380)	(4,145)	(6,185)	(1,745)	(12,460)	(3,360)	(7,705)	(335)	-	(20,386)
Net increase (decrease) in cash and temporary investments	423	-	-	(1)	-	(1)	-	-	-	(10)	411
Cash and Temporary Investments at Beginning of Year	1,294	-	-	2	1	2	-	-	-	8	1,307
Cash and Temporary Investments at End of Year	$ 1,717	$ -	$ -	$ 1	$ 1	$ 1	$ -	$ -	$ -	$ (2)	$ 1,718
Cash paid during the year for interest (Net of amount capitalized as shown above)	$ 307	$ 5,837	$ 10,148	$ 12,236	$ 3,820	$ 28,754	$ 1,608	$ 4,801	$ 203	$ -	$ 67,714

Schedule III