The Commonwealth of Massachusetts

RETURN

OF THE

TOWN OF

HUDSON, LIGHT AND POWER DEPARTMENT

TO THE

DEPARTMENT OF PUBLIC UTILITIES

OF MASSACHUSETTS

For the Year Ended December 31, 1994

1994

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

Official title Manager

Official Address 49 Forest Avenue
Hudson, MA 01749

Form AC-19

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FOR GAS PLANTS ONLY:

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GENERAL INFORMATION

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

Hudson, Ma 01749

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

Kind of plant, whether gas or electric. Electric

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

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

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

Date when town (or city) began to sell gas and electricity

January 15, 1897

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

Horst Huehmer
23 Plant Avenue
Hudson, MA 01749

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

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

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

Virginia Cahill
5 Rockport Road
Southboro, MA 01772

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

Dorothy A. Risser
3 Lincoln Street
Hudson, MA 01749

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

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

8 **Total valuation of estates in town (or city) according to the last State valuation** $951,995,700.00

9 **Tax rate for all purposes during the year:** $16.49 Res
$29.57 Com

10 **Amount of manager's salary:** $98,084.41

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

12 **Amount of salary paid to members of municipal light board (each):** $600.00

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

		Amount
	INCOME FROM PRIVATE CONSUMERS:	
1	From sales of gas	
2	From sales of electricity	$26,123,107.00
3		
4	**TOTAL**	$26,123,107.00
5	**EXPENSES:**	
6	For operation, maintenance and repairs	$24,649,000.00
7	For interest on bonds, notes of scrip	$0.00
8	For depreciation fund (3 per cent. on $18,958,734.36 as per page 9)	$568,762.03
9	For sinking fund requirements	$0.00
10	For note payments	$0.00
11	For bond payments	$0.00
12	For loss in preceding year	$0.00
13		
14	**TOTAL**	$25,217,762.03
15	**COST:**	
16	Of gas to be used for municipal buildings	$0.00
17	Of gas to be used for street lights	$0.00
18	Of electricity to be used for municipal buildings	$593,500.00
19	Of electricity to be used for street lights	$98,800.00
20	Total of the above items to be included in the tax levy	$692,300.00
21		
22	New construction to be included in the tax levy	0
23	Total amounts to be included in the tax levy	$692,300.00

CUSTOMER

Names of the cities or towns in which the plant supplies GAS, with the number of customers' meters in each.		Names of the cities or towns in which the plant supplies ELECTRICITY, with the number of customers' meters in each	
City or Town	**Number of Customers Meters, Dec. 31**	**City or Town**	**Number of Customers Meters, Dec. 31**
		Hudson	7,711
		Stow	2,346
		Berlin, Bolton, Boxboro	
		Harvard, Maynard	
		Marlboro	112
TOTAL		TOTAL	10,169

APPROPRIATIONS SINCE BEGINNING OF YEAR

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

FOR CONSTRUCTION OR PURCHASE OF PLANT:

*At meeting 19 , to be paid from ~

*At meeting 19 , to be paid from ~

TOTAL None

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

1	Street lights	$107,594.78
2	Municipal buildings (Amounts are included in overall appropriations for each Department)	
3		
	TOTAL	$107,594.78

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

CHANGES IN PROPERTY

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

In electric property:

None.

In gas property:

NOT APPLICABLE

BONDS

(Issued on Account of Gas or Electric Lighting.)

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

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

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

TOWN NOTES

(Issued on Account of Gas or Electric Lighting.)

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

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

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

TOTAL COST OF PLANT - ELECTRIC

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

Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1. INTANGIBLE PLANT	$3,879.76	$0.00	$0.00	$0.00	$0.00	$3,879.76
	$3,879.76	$0.00	$0.00	$0.00	$0.00	$3,879.76
2. PRODUCTION PLANT						
A. Steam Production						
310 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
311 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
312 Boiler Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
313 Engines and Engine Driven Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
314 Turbogenerator Unites	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
315 Accessory Electric equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
316 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Steam Production Plant	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
B. Nuclear Production Plant						
320 Land and Land rights	$1,252.93	$0.00	$0.00	$0.00	$0.00	$1,252.93
321 Structures and Improvements	$847,756.63	$606.63	$0.00	$0.00	$0.00	$848,363.26
322 Reactor Plant equipment	$1,255,854.56	$1,726.88	$0.00	$0.00	$0.00	$1,257,581.44
323 Turbogenerator Units	$203,272.44	$18.01	$0.00	$0.00	$0.00	$203,290.45
324 Accessory electric equipment	$304,398.26	($12,135.78)	$0.00	$0.00	$0.00	$292,262.48
325 Miscellaneous Power Plant						$0.00
Equipment	$95,405.51	$1,193.38	$0.00	$0.00	$0.00	$96,598.89
Total Nuclear Production Plant	$2,707,940.33	($8,590.88)	$0.00	$0.00	$0.00	$2,699,349.45

TOTAL COST OF PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	**C. Hydraulic Production Plant**						
2	330 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	331 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	332 Reservoirs, Dams and Waterways	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	333 Water Wheels, Turbines and Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	334 Accessory Electric Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	335 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	336 Roads, Railroads and Bridges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	**D. Other Production Plant**						
10	340 Land and Land Rights	$5,500.00	$0.00	$0.00	$0.00	$0.00	$5,500.00
11	341 Structures and Improvements	$334,270.76	$0.00	$0.00	$0.00	$0.00	$334,270.76
12	342 Fuel Holders, Producers and Accessories	$123,989.32	$0.00	$0.00	$0.00	$0.00	$123,989.32
13	343 Prime Movers	$2,455,596.22	$0.00	$0.00	$0.00	$0.00	$2,455,596.22
14	344 Generators	$296,559.88	$0.00	$0.00	$0.00	($415.55)	$296,144.33
15	345 Accessory Electric Equipment	$832,470.28	$0.00	$0.00	$0.00	$0.00	$832,470.28
16	346 Miscellaneous Power Plant Equipment	$119,580.70	$133.50	$0.00	$0.00	$415.55	$120,129.75
17	**Total Other Production Plant**	$4,167,967.16	$133.50	$0.00	$0.00	$0.00	$4,168,100.66
18	**Total Production Plant**	$6,875,907.49	($8,457.38)	$0.00	$0.00	$0.00	$6,867,450.11
19	**3. TRANSMISSION PLANT**						
20	350 Land and Land Rights	$53,804.14	$0.00	$0.00	$0.00	$0.00	$53,804.14
21	351 Clearing Land and Rights of Way	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
22	352 Structures and Improvements	$168,166.08	$0.00	$0.00	$0.00	$0.00	$168,166.08
23	353 Station Equipment	$396,663.05	$291.93	$0.00	$0.00	$0.00	$396,954.98
24	354 Towers and Fixtures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
25	355 Poles and Fixtures	$796,839.02	$0.00	$0.00	$0.00	$0.00	$796,839.02
26	356 Overhead Conductors and Devices	$227,329.01	$0.00	$0.00	$0.00	$0.00	$227,329.01
27	357 Underground Conduit	$258.07	$0.00	$0.00	$0.00	$0.00	$258.07
28	358 Underground Conductors and Devices	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
29	359 Roads and Trails	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	**Total Transmission Plant**	$1,643,059.37	$291.93	$0.00	$0.00	$0.00	$1,643,351.30

TOTAL COST OF PLANT (Concluded)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance End of Year (g)
1	4. DISTRIBUTION PLANT						
2	360 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	361 Structures and Improvements	$9,286.53	$0.00	$0.00	$0.00	$0.00	$9,286.53
4	362 Station Equipment	$1,841,376.07	$19,359.51	$0.00	$0.00	$0.00	$1,860,735.58
5	363 Storage Battery Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	364 Poles, Towers and Fixtures	$765,359.51	$18,370.40	$0.00	$0.00	$0.00	$783,729.91
7	365 Overhead Conductors and Devices	$1,719,636.30	$28,782.63	$0.00	$0.00	$0.00	$1,748,418.93
8	366 Underground Conduit	$404,347.88	$3,707.87	$0.00	$0.00	$0.00	$408,055.75
9	367 Underground Conductors & Devices	$478,793.81	$9,157.76	$0.00	$0.00	$0.00	$487,951.57
10	368 Line Transformers	$1,987,866.10	$61,101.41	$13,576.21	$0.00	$0.00	$2,035,391.30
11	369 Services	$419,084.70	$7,447.86	$0.00	$0.00	$0.00	$426,532.56
12	370 Meters	$665,532.00	$15,987.49	$5,664.50	$0.00	$0.00	$675,854.99
13	371 Installations on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	372 Leased Prop. on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	373 Street Lighting and Signal Systems	$329,025.66	$1,878.62	$0.00	$0.00	$0.00	$330,904.28
16	Total Distribution Plant	$8,620,308.56	$165,793.55	$19,240.71	$0.00	$0.00	$8,766,861.40
17	5. GENERAL PLANT						
18	389 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
19	390 Structures and Improvements	$474,182.26	$5.66	$0.00	$0.00	$0.00	$474,187.92
20	391 Office Furniture and Equipment	$490,553.25	$72,205.59	$0.00	$0.00	$0.00	$562,758.84
21	392 Transportation Equipment	$502,404.70	$100,162.00	$26,014.47	$0.00	$0.00	$576,552.23
22	393 Stores Equipment	$12,045.77	$0.00	$0.00	$0.00	$0.00	$12,045.77
23	394 Tools, Shop and Garage Equipment	$16,224.04	$4,813.72	$0.00	$0.00	$0.00	$21,037.76
24	395 Laboratory Equipment	$31,799.22	$0.00	$0.00	$0.00	$0.00	$31,799.22
25	396 Power Operated Equipment	$3,497.53	$0.00	$0.00	$0.00	$0.00	$3,497.53
26	397 Communication Equipment	$45,254.44		$0.00	$0.00	$0.00	$45,254.44
27	398 Miscellaneous Equipment	$14,455.46	$5.73	$0.00	$0.00	$0.00	$14,461.19
28	399 Other Tangible Property	$33.72	$0.00	$0.00	$0.00	$0.00	$33.72
29	Total General Plant	$1,590,450.39	$177,192.70	$26,014.47	$0.00	$0.00	$1,741,628.62
30	Total Electric Plant in Service	$18,733,605.57	$334,820.80	$45,255.18	$0.00	$0.00	$19,023,171.19
31					Total Cost of Electric Plant		$19,023,171.19
32							
33					Less Cost of Land, Land Rights, Rights of Way ..		$64,436.83
34					Total Cost upon which Depreciation is based ...		$18,958,734.36

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

COMPARATIVE BALANCE SHEET Assets and Other Debits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	**UTILITY PLANT**			
2	101 Utility Plant - Electric (P.17)	6,696,026.84	6,470,772.58	(225,254.26)
3	101 Utility Plant - Gas (P.20)	0.00	0.00	0.00
4	120 Nuclear Fuel	69,399.38	51,620.46	(17,778.92)
5	Total Utility Plant	6,765,426.22	6,522,393.04	(243,033.18)
6	**OTHER PROPERTY & INVESTMENTS**			
7	123 Invest in Assoc. Companies	146,418.33	146,418.33	0.00
8	124 Other Investments	0.00	0.00	0.00
9	Total Other Prop. & Investment	146,418.33	146,418.33	0.00
10				0.00
11	**FUND ACCOUNTS**			0.00
12	125 Sinking Funds	0.00	0.00	0.00
13	126 Depreciation Fund (P. 14)	1,866,445.86	2,021,856.11	155,410.25
14	128 Other Special Funds	5,671,310.49	9,541,569.86	3,870,259.37
15	Total Funds	7,537,756.35	11,563,425.97	4,025,669.62
16	**CURRENT AND ACCRUED ASSETS**			
17	131 Cash (P. 14)	2,749,139.97	3,178,024.96	428,884.99
18	132 Special Deposits	358,871.67	358,374.96	(496.71)
19	135 Working Funds	500.00	500.00	0.00
20	142 Customer Accounts Receivable	2,964,220.40	2,621,937.73	(342,282.67)
21	143 Other Accounts Receivable	39,235.88	40,849.21	1,613.33
22	146 Receivables from Municipality	2,286.36	2,286.36	0.00
23	151 Materials and Supplies (P.14)	1,091,409.09	1,061,044.82	(30,364.27)
24	165 Prepayments	419,012.69	460,879.34	41,866.65
25	171 Dividend & Int. Receivable	45,771.61	178,917.38	133,145.77
26	173 Accrued Utility Revenues	0.00	0.00	0.00
27	174 Miscellaneous Current Assets	971.14	970.20	(0.94)
28	Total Current and Accrued Assets	7,671,418.81	7,903,784.96	232,366.15
29	**DEFERRED DEBITS**			
30	181 Unamortized Debt Discount	0.00	0.00	0.00
31	182 Extraordinary Property Losses	0.00	0.00	0.00
32	185 Other Deferred Debits	368,668.72	368,668.72	0.00
33	Total Deferred Debits	368,668.72	368,668.72	0.00
34				
35	Total Assets and Other Debits	22,489,688.43	26,504,691.02	4,015,002.59

COMPARATIVE BALANCE SHEET Liabilities and Other Credits

Line No.	Title of Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Increase or (Decrease) (d)
1	**APPROPRIATIONS**			
2	201 Appropriations for Construction	$0.00	$0.00	$0.00
3	**SURPLUS**			
4	205 Sinking Fund Reserves	$0.00	$0.00	$0.00
5	206 Loans Repayments	$1,925,000.00	$1,925,000.00	$0.00
6	207 Appropriations for Construction Repayments	$20,093.39	$20,093.39	$0.00
7	208 Unappropriated Earned Surplus (P.12)	$17,307,278.89	$22,063,561.60	$4,756,282.71
8	Total Surplus	$19,252,372.28	$24,008,654.99	$4,756,282.71
9	**LONG TERM DEBT**			
10	221 Bonds (P.6)	$0.00	$0.00	$0.00
11	231 Notes Payable (P.7)	$0.00	$0.00	$0.00
12	Total Bonds and Notes	$0.00	$0.00	$0.00
13	**CURRENT & ACCRUED LIABILITIES**			
14	232 Accounts Payable	$641,992.96	$586,420.70	($55,572.26)
15	234 Payables to Municipality	$0.00	$0.00	$0.00
16	235 Customer' Deposits	$358,871.67	$358,374.96	($496.71)
17	236 Taxes .... Collection Payable	$18,903.78	$16,452.20	($2,451.58)
18	237 Interest Accrued	$0.00	$0.00	$0.00
19	242 Miscellaneous Current and Accrued Liabilities	$116.03	$116.03	$0.00
20	Total Current and Accrued Liabilities	$1,019,884.44	$961,363.89	($58,520.55)
21	**DEFERRED CREDITS**			
22	251 Unamortized Premium on Debt	$0.00	$0.00	$0.00
23	252 Customer Advances for Construction	$2,100.00	$2,100.00	$0.00
24	253 Other Deferred Credits	$1,201,277.98	$518,518.41	($682,759.57)
25	Total Deferred Credits	$1,203,377.98	$520,618.41	($682,759.57)
26	**RESERVES**			
27	260 Reserves for Uncollectible Accounts	$0.00	$0.00	$0.00
28	261 Property Insurance Reserve	$0.00	$0.00	$0.00
29	262 Injuries and Damages Reserves	$605,394.41	$605,394.41	$0.00
30	263 Pensions and Benefits	$0.00	$0.00	$0.00
31	265 Miscellaneous Operating Reserves	$0.00	$0.00	$0.00
32	Total Reserves	$605,394.41	$605,394.41	$0.00
33	**CONTRIBUTIONS IN AID OF CONSTRUCTION**			
34	271 Contributions in Aid of Construction	$408,659.32	$408,659.32	$0.00
35	Total Liabilities and Other Credits	$22,489,688.43	$26,504,691.02	$4,015,002.59

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

Transferred $200,000.00 to town

STATEMENT OF INCOME FOR THE YEAR

Line No.	Account (a)	Total: Current Year (b)	Total: Increase or (Decrease) from Preceding Year (c)
1	**OPERATING INCOME**		
2	400 Operating Revenues (P. 37 and 43)	$27,127,606.71	($135,134.97)
3	Operating Expenses		
4	401 Operating Expenses (P. 42 and 47)	$24,862,701.72	($200,061.89)
5	402 Maintenance Expenses (P. 42 and 47)	$633,151.46	$108,652.96
6	403 Depreciation Expenses	$560,075.06	$31,244.52
7	407 Amortization of Property Losses	$0.00	$0.00
8			
9	408 Taxes (P. 49)	$17,043.13	($7,293.30)
10	Total Operating Expenses	$26,072,971.37	($67,457.71)
11	Operating Income	$1,054,635.34	($67,677.26)
12	414 Other Utility Operating Income (P. 50)	$0.00	$0.00
13			
14	Total Operating Income	$1,054,635.34	($67,677.26)
15	**OTHER INCOME**		
16	415 Income from Merchandising, Jobbing and Contract Work (P. 51)	$0.00	$0.00
17	419 Interest Income	$356,826.13	$155,761.62
18	421 Miscellaneous Nonoperating Income	$1,537.93	$104.59
19	Total Other Income	$358,364.06	$155,866.21
20	Total Income	$1,412,999.40	$88,188.95
21	**MISCELLANEOUS INCOME DEDUCTIONS**		
22	425 Miscellaneous Amortization	$0.00	$0.00
23	426 Other Income Deductions	$168.37	$27.92
24	Total Income Deductions	$168.37	$27.92
25	Income Before Interest Charges	$1,412,831.03	$88,161.03
26	**INTEREST CHARGES**		
27	427 Interest on Bonds and Notes	$0.00	$0.00
28	428 Amortization of Debt Discount and Expenses	$0.00	$0.00
29	429 Amortization of Premium on Debt - Credit	$0.00	$0.00
30	431 Other Interest Expenses	$234.87	($467.08)
31	432 Interest Charged to Construction - Credit	$0.00	$0.00
32	Total Interest Charges	$234.87	($467.08)
33	NET INCOME	$1,412,596.16	$88,628.11

EARNED SURPLUS

Line No.	(a)	Debits (b)	Credits (c)
34	208 Unappropriated Earned Surplus (at beginning of period)		$17,307,278.89
35			
36			
37	433 Balance Transferred from Income		$1,412,596.16
38	434 Miscellaneous Credits to Surplus (P. 21)		$3,543,686.55
39	435 Miscellaneous Debits to Surplus (P. 21)		
40	436 Appropriations of Surplus (P. 21)	$200,000.00	
41	437 Surplus Applied to Depreciation		
42	208 Unappropriated Earned Surplus (at end of period)	$22,063,561.60	
43			
44	TOTALS	$22,263,561.60	$22,263,561.60

CASH BALANCES AT END OF YEAR (Account 131)

Line No.	Items (a)	Amount (b)
1	Operation Fund	$3,178,024.96
2	Interest Fund	$0.00
3	Bond Fund	$0.00
4	Construction Fund (128)	$0.00
5	Miscellaneous Cash (128)	$1,608,964.45
6	Insurance Escrow Reserve (128)	$7,932,605.41
7		
8		
9		
10		
11		
12	TOTAL	$12,719,594.82

MATERIALS AND SUPPLIES (Accounts 151-159, 163)

Summary Per Balance Sheet

Line No.	Account (a)	Amount End of Year	
		Electric (b)	Gas (c)
13	Fuel (Account 151) (See Schedule, Page 25)	$171,269.62	
14	Fuels Stock Expenses (Account 152)		
15	Residuals (Account 153)		
16	Plant Materials and Operating Supplies (Account 154)	$1,061,044.82	NOT APPLICABLE
17	Merchandise (Account 155)		
18	Other Materials and Supplies (Account 156)		
19	Nuclear Fuels Assemblies and Components - In Reactor (Account 157)		
20	Nuclear Fuels Assemblies and Components - Stock Account (Account 158)		
21	Nuclear Byproduct Materials (Account 159)		
22	Stores Expense (Account 163)		
23	Total Per Balance Sheet $	$1,232,314.44	

DEPRECIATION FUND ACCOUNT (Account 136)

Line No.	(a)	Amount (b)
24	**DEBITS**	
25	Balance of account at beginning of year	$1,866,445.86
26	Income during year from balance on deposit	$60,529.68
27	Amount transferred from income	$560,075.06
28	Reimbursement from sales of plant and damages property, etc.	$0.00
29	TOTAL	$2,487,050.60
30	**CREDITS**	
31	Amount expended for construction purposes(Sec.57,C164 of G.L.)	$465,194.49
32	Amounts expended for renewals, viz:	
33		
34		
35		
36		
37		
38		
39	Balance on hand at end of year	$2,021,856.11
40	TOTAL	$2,487,050.60

UTILITY PLANT - ELECTRIC

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

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

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1							
2	**1. INTANGIBLE PLANT**	$3,879.76					$3,879.76
3							
4	**Total Intangible Plant**	$3,879.76					$3,879.76
5	**2. PRODUCTION PLANT**						
6	**A. Steam Production**						
7	310 Land and Land rights						
8	311 Structures and Improvements						
9	312 Boiler Plant equipment						
10	313 Engine and Engine Driven						
11	Generators						
12	314 Turbogenerator Units						
13	315 Miscellaneous Power Plant						
14	Equipment						
15	**Total Steam Production Plant**						
16	**B. Nuclear Production Plant**						
17	320 Land and Land Rights	$1,252.93	$0.00	$0.00	$0.00	$0.00	$1,252.93
18	321 Structures and Improvements	$746,330.41	$606.63	$25,432.70	$0.00	$0.00	$721,504.34
19	322 Reactor Plant Equipment	$1,129,785.47	$1,726.88	$47,675.64	$0.00	$0.00	$1,083,836.71
20	323 Turbogenerator Units	$160,593.77	$18.01	$6,098.17	$0.00	$0.00	$154,513.61
21	324 Accessory Electric Equipment	$251,682.05	($12,135.78)	$9,131.95	$0.00	$0.00	$230,414.32
22	325 Miscellaneous Power Plant Equipment	$77,523.23	$1,193.38	$2,862.17	$0.00	$0.00	$75,854.44
23	**Total Nuclear Production Plant**	$2,367,167.86	($8,590.88)	$91,200.63	$0.00	$0.00	$2,267,376.35

UTILITY PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits (e)	Adjustments Transfers (f)	Balance End of Year (g)
1	**C. Hydraulic Production Plant**						
2	330 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	331 Structures and Improvements	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	332 Reservoirs, Dams and Waterways	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	333 Water Wheels, turbines and Generators	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	334 Accessory Electric equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7	335 Miscellaneous Power Plant Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8	336 Roads, Railroads and Bridges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
9	**Total Hydraulic Production Plant**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	**D. Other Production Plant**						
11	340 Land and Land Rights	$5,500.00	$0.00	$0.00	$0.00	$0.00	$5,500.00
12	341 Structures and Improvements	$7,972.76	$0.00	$1,002.81	$0.00	$0.00	$6,969.95
13	342 Fuel Holders, Producers and Accessories	$10,271.91	$0.00	$371.97	$0.00	$0.00	$9,899.94
14	343 Prime Movers	$80,988.05	$0.00	$7,366.78	$0.00	$0.00	$73,621.27
15	344 Generators	$4,380.37	$0.00	$889.68	$0.00	($415.55)	$3,075.14
16	345 Accessory Electric Equipment	$24,300.45	$0.00	$2,497.41	$0.00	$0.00	$21,803.04
17	346 Miscellaneous Power Plant Equipment	$71,677.52	$133.50	$3,587.42	$0.00	$415.55	$68,639.15
18	**Total Other Production Plant**	$205,091.06	$133.50	$15,716.07	$0.00	$0.00	$189,508.49
19	**Total Production Plant**	$2,572,258.92	($8,457.38)	$106,916.70	$0.00	$0.00	$2,456,884.84
20	**3. TRANSMISSION PLANT**						
21	350 Land and Land Rights	$53,804.14	$0.00	$0.00	$0.00	$0.00	$53,804.14
22	351 Clearing Land and Rights of Way	$6,812.85	$0.00	$0.00	$0.00	($6,812.85)	$0.00
23	352 Structures and Improvements	$19,916.07	$0.00	$2,544.98	$0.00	$6,812.85	$24,183.94
24	353 Station Equipment	$97,726.95	$291.93	$9,037.13	$0.00	$0.00	$88,981.75
25	354 Towers and Fixtures	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
26	355 Poles and Fixtures	$54,850.33	$0.00	$5,976.29	$0.00	$0.00	$48,874.04
27	356 Overhead Conductors and Devices	$39,393.96	$0.00	$3,819.87	$0.00	$0.00	$35,574.09
28	357 Underground Conduit	$75.38	$0.00	$7.74	$0.00	$0.00	$67.64
29	358 Underground Conduit and Devices	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
30	359 Roads and Trails	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	**Total Transmission Plant**	$272,579.68	$291.93	$21,386.01	$0.00	$0.00	$251,485.60

UTILITY PLANT - ELECTRIC (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Depreciation (d)	Other Credits	Adjustments Transfers (i)	Balance End of Year (g)
1	**4. DISTRIBUTION PLANT**						
2	360 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	361 Structures and Improvements	$5,066.91	$0.00	$578.60	$0.00	$0.00	$4,488.31
4	362 Station Equipment	$1,451,877.03	$19,359.51	$155,241.28	$0.00	$0.00	$1,315,995.26
5	363 Storage Battery Equipment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	364 Poles, Towers and Fixtures	$134,079.76	$34,969.31	$22,960.79	$16,598.91	$0.00	$129,489.37
7	365 Overhead Conductors and Devices	$57,840.25	$43,904.48	$16,589.09	$15,121.85	$0.00	$70,033.79
8	366 Underground Conduit	$235,472.67	$4,684.02	$42,130.44	$976.15	$0.00	$197,050.10
9	367 Underground Conductors & Devices	$231,282.11	$13,674.87	$48,363.81	$4,517.11	$0.00	$192,076.06
10	368 Line Transformers	$779,590.57	$62,123.21	$59,635.98	$1,021.80	$0.00	$781,056.00
11	369 Services	$89,941.09	$18,300.84	$12,572.54	$10,852.98	$0.00	$84,816.41
12	370 Meters	$324,348.62	$18,172.75	$19,965.92	$2,185.26	$0.00	$320,370.19
13	371 Installations on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
14	372 Leased Prop. on Cust's Premises	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15	373 Street Lighting and Signal Systems	$61,976.73	$3,165.47	$9,870.77	$1,286.85	$0.00	$53,984.58
16	**Total Distribution Plant**	$3,371,475.74	$218,354.46	$387,909.22	$52,560.91	$0.00	$3,149,360.07
17	**5. GENERAL PLANT**						
18	389 Land and Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
19	390 Structures and Improvements	$73,347.38	$5.66	$7,172.06	$0.00	$0.00	$66,180.98
20	391 Office Furniture and Equipment	$196,667.27	$84,987.59	$16,953.90	$12,782.00	$0.00	$251,918.96
21	392 Transportation Equipment	$153,086.28	$100,662.00	$15,072.14	$500.00	$0.00	$238,176.14
22	393 Stores Equipment	$3,043.33	$0.00	$361.37	$0.00	$0.00	$2,681.96
23	394 Tools, Shop and Garage Equipment	$7,172.94	$4,813.72	$526.03	$0.00	$0.00	$11,460.63
24	395 Laboratory Equipment	$17,387.73	$0.00	$1,253.98	$0.00	$0.00	$16,133.75
25	396 Power Operated Equipment	$1,914.85	$0.00	$204.93	$0.00	$0.00	$1,709.92
26	397 Communication Equipment	$15,847.74	$0.00	$1,557.63	$0.00	$0.00	$14,290.11
27	398 Miscellaneous equipment	$7,334.87	$5.73	$761.09	$0.00	$0.00	$6,579.51
28	399 Other Tangible Property	$30.35	$0.00	$0.00	$0.00	$0.00	$30.35
29	**Total General Plant**	$475,832.74	$190,474.70	$43,863.13	$13,282.00	$0.00	$609,162.31
30	**Total Electric Plant in Service**	$6,696,026.84	$400,663.71	$560,075.06	$65,842.91	$0.00	$6,470,772.58
31	104 Utility Plant Leased to Others	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32	105 Property Held for Future Use	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
33	107 Construction Work in Progress	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
34	**Total Utility Plant Electric**	$6,696,026.84	$400,663.71	$560,075.06	$65,842.91	$0.00	$6,470,772.58

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

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

Line No.	Item (a)	Total Cost (b)	Kind of Fuel and Oil: Quantity (c)	Cost (d)	GAS MCF: Quantity (e)	Cost (f)
1	On Hand Beginning of Year	$236,498.87	391,522	$236,498.87	0	$0.00
2	Received During Year	$96,508.80	0	$0.00	32,765	$96,508.80
3	**TOTAL**	$333,007.67	391,522	$236,498.87	32,765	$96,508.80
4	Used During Year (Note A)	$161,738.05	107,999	$65,229.25	32,765	$96,508.80
5						
6						
7						
8						
9						
10						
11	Sold or Transferred	$0.00	0	$0.00	0	$0.00
12	**TOTAL DISPOSED OF**	$161,738.05	107,999	$65,229.25	32,765	$96,508.80
13	**BALANCE END OF YEAR**	$171,269.62	283,523	$171,269.62	0	$0.00

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

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

MISCELLANEOUS NONOPERATING INCOME (ACCOUNT 421)

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

OTHER INCOME DEDUCTIONS (ACCOUNT 426)

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

MISCELLANEOUS CREDITS TO SURPLUS (ACCOUNT 434)

Line No.	Item (a)	Amount (b)
15	Eastern Maine Electric Cooperative Settlement	$3,543,686.55
16		
17		
18		
19		
20		
21		
22		
23	TOTAL	$3,543,686.55

MISCELLANEOUS DEBITS TO SURPLUS (ACCOUNT 435)

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

APPROPRIATIONS OF SURPLUS (ACCOUNT 436)

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

MUNICIPAL REVENUES (ACCOUNTS 482, 444)

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

Line No.	Acct. No.	Gas Schedule (a)	Cubic Feet (b)	Revenue Received (c)	Average Revenue per M.C.F. ($0.0000) (d)
1	482	NOT APPLICABLE			
2					
3					
4					
		Electric Schedule (a)	**K.W.H. (b)**	**Revenue Received (c)**	**Average Revenue perK.W.H.. (cents) (0.0000) (d)**
5	444	Municipal (Other than Street Lighting)			
6					
7		All Electric	6,272,100	$494,482.61	7.8838
8		Power	5,374,431	$525,752.77	9.7825
9		Commercial	528,579	$63,665.23	12.0446
10		Yard Lighting	25,067	$2,992.61	11.9384
11		TOTALS	12,200,177	$1,086,893.22	8.9088
12					
13		Street Lighting			
14					
15		Town of Hudson	1,160,801	$106,295.77	9.1571
16		Town of Stow	27,443	$3,727.87	13.5840
17		Town of Berlin	388	$66.55	17.1521
18		TOTALS	1,188,632	$110,090.19	9.2619
19		TOTALS	13,388,809	$1,196,983.41	8.9402

PURCHASED POWER (ACCOUNT 555)

Line No.	Names of Utilities from Which Electric Energy is Purchased (a)	Where and at What Voltage Received (b)	K.W.H. (c)	Amount (d)	Cost per K.W.H. (cents) (0.0000) (e)
20	See Pages 54, 55, 56 for Details				
21					
22					
23					
24					
25					
26					
27					
28					
29		TOTALS	320,893,522	$21,764,650.84	6.7825

SALES FOR RESALE (ACCOUNT 447)

Line No.	Names of Utilities to Which Electric Energy is Purchased (a)	Where and at What Voltage Received (b)	K.W.H. (c)	Amount (d)	Revenues per K.W.H. (cents) (0.0000) (e)
30	See Pages 52,53 for details				
32					
33					
34					
35					
36					
37					
38					
39					
40		TOTALS	279,800	$15,293.51	5.4658

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Account (a)	Operating Revenues		Kilowatt-hours Sold		Average Number of Customers per month	
		Amount for Year (b)	Increase of (Decrease) from Preceding Year (c)	Amount for Year (d)	Increase or (Decrease) from Preceding Year (e)	Number for Year (f)	Increase or (Decrease) from Preceding Year (g)
1	SALES OF ELECTRICITY						
2	440 Residential Sales	$6,400,309.94	($990,868.29)	70,167,817	2,574,730	8,862	196
3	442 Commercial and Industrial Sales:						
4	Small (or Commercial) see instr. 5	$1,484,858.75	($219,142.43)	11,979,034	231,196	974	(128)
5	Large (or Industrial) see instr. 5	$17,237,596.96	$139,807.94	210,469,687	46,682,462	185	(4)
6	444 <Municipal Sales; (P. 22)	$1,196,983.41	($212,676.45)	13,388,809	73,312	90	2
7	445 Other Sales to Public Authorities	$0.00	$0.00	0	0	0	0
8	446 Sales to Railroads and Railways	$0.00	$0.00	0	0	0	0
9	449 Fuel Charge Adjustment	$683,333.24	$1,135,532.40	0	0	0	0
10	449 Miscellaneous Electric Sales	$67,371.96	($4,879.83)	552,146	22,371	167	5
11	**Total Sales to Ultimate Consumers**	$27,070,454.26	($152,226.66)	306,557,493	49,584,071	10,278	71
12	**447 Sales for Resale**	$15,293.51	$15,293.51	279,800	279,800	0	0
13	**Total Sales of Electricity***	$27,085,747.77	($136,933.15)	306,837,293	49,863,871	10,278	71
14	**OTHER OPERATING REVENUES**						
15	**450 Forfeited Discounts**						
16	**451 Miscellaneous Service Revenues**	$0.00	$0.00				
17	**453 Sales of Water and Water Power**	$0.00	$0.00	*Includes revenues from application of fuel clauses		$	$3,908,949.62
18	**454 Rent fro Electric Property**	$27,484.00	$0.00				
19	**455 Interdepartmental Rents**	$0.00	$0.00				
20	**456 Other Electric Revenues**	$14,374.94	($1,798.18)	Total KWH to which applied			305,396,692
21							
22							
24							
25	**Total Other Operating Revenues**	$41,858.94	($1,798.18)				
26	**Total Electric Operating Revenues**	$27,127,606.71	($135,134.97)				

SALES OF ELECTRICITY TO ULTIMATE CONSUMERS

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

Line No.	Acct. No.	Schedule (a)	K.W.H. (b)	Revenue (c)	Average Revenue per KWH (cents) (0.0000) (d)	Number of Customers (Per Bills Rendered) July 31, (e)	Dec. 31, (f)
1	440	"A" Domestic Rate	42,236,887	$4,030,938.05	9.5436	6,824	6,876
2	442	"C" Commercial Rate	11,917,520	$1,477,467.80	12.3974	956	970
3	442	"D" Power Rate	210,469,687	$17,237,596.96	8.1901	184	174
4	440	"E" Water Heater Residential	11,194,459	$983,290.48	8.7837	1,158	1,160
5	440	"F" Rate All Electric	16,736,471	$1,386,081.41	8.2818	906	903
6	442	"G" Rate Commercial Heat	61,514	$7,390.95	12.0151	3	3
7	444	Street Lighting	1,188,632	$110,090.19	9.2619	3	3
8	444	Municipal Sales	12,200,177	$1,086,893.22	8.9088	91	90
9	449	Yard Lighting	552,146	$67,371.96	12.2018	167	166
10	449	Power Adjustment Charge	0	$683,333.24			
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49	TOTAL SALES TO ULTIMATE CONSUMERS (Page 37 line 11)		306,557,493	$27,070,454.26	8.8305	10,292	10,345

ELECTRIC OPERATING AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**POWER PRODUCTION EXPENSES**		
2	**STEAM POWER GENERATION**		
3	Operation:		
4	500 Operation supervision and engineering		
5	501 Fuel		
6	502 Steam expenses		
7	503 Steam from other sources		
8	504 Steam transferred - Cr.		
9	505 Electric expenses		
10	506 Miscellaneous steam power expenses		
11	507 Rents		
12	Total Operation	$0.00	$0.00
13	Maintenance:		
14	510 Maintenance supervision and engineering		
15	511 Maintenance of structures		
16	512 Maintenance of boiler plant		
17	513 Maintenance of electric plant		
18	514 Maintenance of miscellaneous steam plant		
19	Total Maintenance	$0.00	$0.00
20	Total power production expenses - steam power	$0.00	$0.00
21	**NUCLEAR POWER GENERATION**		
22	Operation:		
23	517 Operation supervision and engineering	$16,222.35	$318.77
24	518 Fuel	$25,198.53	($16,788.90)
25	519 Coolants and water	$550.38	$78.41
26	520 Steam expenses	$11,988.13	$2,025.51
27	521 Steam from other courses	$0.00	$0.00
28	522 Steam transferred - Cr.	$0.00	$0.00
29	523 Electric expenses	$224.12	($108.62)
30	524 Miscellaneous nuclear power expenses	$27,658.90	$4,872.23
31	525 Rents	$0.00	$0.00
32	Total operation	$81,842.41	($9,602.60)
33	Maintenance		
34	528 Maintenance supervision and engineering	$7,193.28	$2,255.26
35	529 Maintenance of structures	$3,365.71	$72.45
36	530 Maintenance of reactor plant equipment	$11,734.14	$9,406.22
37	531 Maintenance of electric plant	$6,273.24	$3,258.20
38	532 Maintenance of miscellaneous nuclear plant	$8,502.22	$2,578.10
39	Total maintenance	$37,068.59	$17,570.23
40	Total power production expenses-nuclear power	$118,911.00	$7,967.63
41	**HYDRAULIC POWER GENERATION**		
42	Operation		
43	535 Operation supervision and engineering		
44	536 Water for power		
45	537 Hydraulic expenses		
46	538 Electric expenses		
47	539 Miscellaneous hydraulic power generation expenses		
48	540 Rents		
49	Total operation		

ELECTRIC OPERATING AND MAINTENANCE EXPENSES - Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**HYDRAULIC POWER GENERATION - Continued**		
2	Maintenance		
3	541 Maintenance supervision and engineering		
4	542 Maintenance of structure		
5	543 Maintenance of reservoirs, dams and waterways		
6	544 Maintenance of electric plant		
7	545 Maintenance of miscellaneous hydraulic plant		
8	Total maintenance		
9	Total power production expenses - hydraulic power		
10	**OTHER POWER GENERATION**		
11	Operation		
12	546 Operation supervision and engineering	$27,089.19	$2,132.94
13	547 Fuel	$161,738.05	$90,137.36
14	548 Generation expenses	$181,895.18	($18,438.50)
15	549 Miscellaneous other power generation expenses	$64,703.35	$5,683.44
16	550 Rent	$0.00	$0.00
17	Total operation	$435,425.77	$79,515.24
18	Maintenance		
19	551 Maintenance supervision and engineering	$26,179.17	$1,688.79
20	552 Maintenance of structures	$51,643.15	($67,019.61)
21	553 Maintenance of generating and electric plant	$104,751.50	$55,646.53
22	554 Maintenance of miscellaneous other power generation plant	$2,407.72	($1,747.76)
23	Total maintenance	$184,981.54	($11,432.05)
24	Total power production expenses	$620,407.31	$68,083.19
25	**OTHER POWER SUPPLY EXPENSES**		
26	555 Purchased power	$21,764,650.84	($424,459.26)
27	556 System control and load dispatching	$19,142.36	($6,398.48)
28	557 Other expenses	$42,441.45	$13,815.78
29	Total other power supply expenses	$21,826,234.65	($417,041.96)
30	Total power production expenses	$22,565,552.96	($340,991.14)
31	**TRANSMISSION EXPENSES**		
32	Operation		
33	560 Operation supervision and engineering	$0.00	$0.00
34	561 Load dispatching	$0.00	$0.00
35	562 Station Expenses	$439.99	($3,468.46)
36	563 Overhead line expenses	$51.72	$14.40
37	564 Underground line expenses	$0.00	$0.00
38	565 Transmission of electricity by others	$899,827.54	($15,854.38)
39	566 Miscellaneous transmission expenses	$0.00	$0.00
40	567 Rents	$0.00	($50.00)
41	Total operation	$900,319.25	($19,358.44)
42	Maintenance		
43	568 Maintenance supervision and engineering	$0.00	$0.00
44	569 Maintenance of structures	$2,072.71	$1,743.99
45	570 Maintenance of station equipment	$3,151.67	($14.61)
46	571 Maintenance of overhead lines	$333.82	$218.96
47	572 Maintenance of underground lines	$0.00	$0.00
48	573 Maintenance of miscellaneous transmission plant	$0.00	$0.00
49	Total maintenance	$5,558.20	$1,948.34
	Total transmission expenses	$905,877.45	($17,410.10)

ELECTRIC OPERATING AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**DISTRIBUTION EXPENSES**		
2	Operation:		
3	580 Operation supervision and engineering	$25,623.05	$2,944.45
4	581 Load dispatching	$0.00	$0.00
5	582 Station expenses	$1,503.94	$1,216.38
6	583 Overhead line expenses	$6,999.56	($81.55)
7	584 Underground line expenses	$1,142.19	($777.29)
8	585 Street lighting and signal system expenses	$8,961.51	$551.30
9	586 Meter expenses	$51,032.42	$5,994.07
10	587 Customer installations expenses	$2,184.85	$915.71
11	588 Miscellaneous distribution expenses	$13,171.79	$7,397.10
12	589 Rents	$0.00	$0.00
13	Total operation	$110,619.31	$18,160.17
14	Maintenance:		
15	590 Maintenance supervision and engineering	$25,534.73	$2,805.40
16	591 Maintenance of structures	$0.00	$0.00
17	592 Maintenance of station equipment	$31,292.23	$31,110.39
18	593 Maintenance of overhead lines	$207,573.47	$18,291.93
19	594 Maintenance of underground lines	$17,715.84	($3,528.04)
20	595 Maintenance of line transformers	$18,665.69	$10,071.98
21	596 Maintenance of street lighting and signal systems	$8,431.83	$1,286.76
22	597 Maintenance of meters	$1,280.08	($5,734.25)
23	598 Maintenance of miscellaneous distribution plant	$0.00	$0.00
24	Total maintenance	$310,493.87	$54,304.17
25	Total distribution expenses	$421,113.18	$72,464.34
26	**CUSTOMERS ACCOUNTS EXPENSES**		
27	Operation:		
28	901 Supervision	$11,375.37	$742.66
29	902 Meter reading expenses	$47,000.61	($55.20)
30	903 Customer records and collection expenses	$172,537.60	$3,387.99
31	904 Uncollectible accounts	$46,143.29	$2,186.27
32	905 Miscellaneous customer accounts expenses	$0.00	$0.00
33	Total customer accounts expenses	$277,056.87	$6,261.72
34	**SALES EXPENSES**		
35	Operation:		
36	911 Supervision	$0.00	$0.00
37	912 Demonstrating and selling expenses	$0.00	$0.00
38	913 Advertising expenses	$105.00	$80.00
39	916 Miscellaneous sales expenses	$16,383.37	$4,600.49
40	Total sales expenses	$16,488.37	$4,680.49
41	**ADMINISTRATIVE AND GENERAL EXPENSES**		
42	Operation:		
43	920 Administrative and general salaries	$350,905.21	$31,326.05
44	921 Office supplies and expenses	$11,731.30	$1,962.85
45	922 Administrative expenses transferred - Cr.	($66.08)	($37.52)
46	923 Outside services employees	$222,701.63	$31,739.56
47	924 Property insurance	$29,835.76	$3,087.44
48	925 Injuries and damages	$111,468.92	$64,254.44
49	926 Employee pensions and benefits	$389,636.93	($3,683.50)
50	928 Regulatory commission expenses	$3,162.56	($352.16)
51	933 Transportation expenses	$55,836.33	$15,995.65
52	930 Miscellaneous general expenses	$39,502.53	($6,969.32)
53	931 Rents	$0.00	$0.00
54	Total operation	$1,214,715.09	$137,323.49

ELECTRIC OPERATION AND MAINTENANCE EXPENSES - Continued

Line No.	Account (a)	Amount for Year (b)	Increase or (Decrease) from Preceding Year (c)
1	**ADMINISTRATIVE AND GENERAL EXPENSES - Cont.**		
2	Maintenance		
3	932 Maintenance of general plant	$95,049.26	$46,262.27
4	Total administrative and general expenses	$1,309,764.35	$183,585.76
5	Total Electric Operation and Maintenance Expenses	$25,495,853.18	($91,408.93)

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
6	Power Production Expenses			
7	Electric Generation:			
8	Steam power			
9	Nuclear power	$81,842.41	$37,068.59	$118,911.00
10	Hydraulic power			
11	Other power	$435,425.77	$184,981.54	$620,407.31
12	Other power supply expenses	$21,826,234.65	$0.00	$21,826,234.65
13	Total power production expenses	$22,343,502.83	$222,050.13	$22,565,552.96
14	Transmission Expenses	$900,319.25	$5,558.20	$905,877.45
15	Distribution Expenses	$110,619.31	$310,493.87	$421,113.18
16	Customer Accounts Expenses	$277,056.87	$0.00	$277,056.87
17	Sales Expenses	$16,488.37	$0.00	$16,488.37
18	Administrative and General Expenses	$1,214,715.09	$95,049.26	$1,309,764.35
19	Total Electric Operation and			
20	Maintenance Expenses	$24,862,701.72	$633,151.46	$25,495,853.18

21	Ratio operating expenses to operating revenues (carry out decimal two places, e.g.: 0.00%) Complete by dividing Revenues (acct. 400) into the sum of Operation and Maintenance Expenses (Page 42, line 20(d), Depreciation (Acct. 403) and Amortization (Acct. 407)	96.11%
22	Total salaries and wages of electric department for year, including amounts charged to operating expenses, construction and other accounts.	$1,446,100.01
23	Total number of employees of electric department at end of year including administrative, operating, maintenance, construction and other employees (including part time employees)	35

TAXES CHARGED DURING YEAR

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

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

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

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

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

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

Line No.	Kind of Tax (a)	Total Taxes Charged During Year (omit cents) (b)	Distribution of Taxes Charged (omit cents) (Show utility department where applicable and account charged) Electric (Acct. 408, 409) (c)	Gas (Acct. 408, 409) (d)	(e)	(f)	(g)	(h)	(j)	(k)
1	Real Estate Taxes	$13,986.73	$13,986.73							
2	Payroll Taxes	$3,039.16	$3,039.16							
3	Income Taxes	$17.24	$17.24							
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28	TOTALS	$17,043.13	$17,043.13							

OTHER UTILITY OPERATION INCOME (Account 414)

Report below the particulars called for in each column.

Line No.	Property (a)	Amount of Investment (b)	Amount of Revenue (c)	Amount of Operating Expenses (d)	Gain or (Loss) from Operation (e)
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20	**NONE**				
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49					
50					
51	TOTALS				

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

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

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

SALES FOR RESALE (Account 447)

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

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

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

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

Line No.	Sales to (a)	(b)	(c)	Point of Delivery (d)	(e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1	Non Associated Utilities							
2	Central Vt. P. S. Corp	G	X	Marlboro-Hudson				
3				Line		3000	NA	NA
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SALES FOR RESALE (Account 447) - Continued

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

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

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

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

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	Demand Charges (l)	Energy (m)	Other Charges (n)	Total (o)	Revenue per KWH (Cents) (0.0000) (p)	Line No.
NA	115 KVA	279,800	2500	$12,793.57	0	$15,293.51	5.4658	1
								2
								3
								4
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	TOTALS	279,800	2500	$12,793.57	0	$15,293.51	5.4658	42

PURCHASED POWER (Account 555)
(except interchange power)

1. Report power purchased for resale during the year. Exclude from this schedule and report on page 56 particulars concerning interchange power transactions during the year.

2. Provide subheadings and classify purchases as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Nonassociated Utilities, (5) Municipalities, (6) R.E.A. Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b), thus: firm power, FP; dump or surplus power, DP; other, O, and place and "x" in column (c) if purchase involves import across a state line.

3. Report separately firm, dump, and other power purchased from the same company. Describe the nature of any purchases classified as Other Power, column (b).

Line No.	Purchsed from (a)	Statistical Classification (b)	Import Accros State Lines (c)	Point of Receipt (d)	Substation (e)	Kw or Kva of Demand (Specify Which) Contract Demand (f)	Average Monthly Maximum Demand (g)	Annual Maximum Demand (h)
1	Pilgrim I - Boston Edison	O		Marlboro-Hudson Line		2500	N/A	N/A
2	Vermont Yankee	O	X			578	N/A	N/A
3	Maine Yankee	O	X			1310	N/A	N/A
4	Wyman - Yarmouth - CM	O	X			2102	N/A	N/A
5	Point Lepreau	O	X			2500	N/A	N/A
6	MMWEC - Canal	O				3141	N/A	N/A
7	MMWEC - Mix No. 1	O	X			691	N/A	N/A
8	MMWEC - Project #3 - M	O	X			591	N/A	N/A
9	MMWEC - Project #4	O	X			2109	N/A	N/A
10	MMWEC- Project #5	O	X			235	N/A	N/A
11	MMWEC - Project #6	O	X			15972	N/A	N/A
12	Taunton - Cleary Station	O				5000	N/A	N/A
13	Pasny	O	X			2521	N/A	N/A
14	RFA - Lawrence	O				829	N/A	N/A
15	N.E. Power Co.	O				6000	N/A	N/A
16	MMWEC - System	O				3500	N/A	N/A
17	Northeast Utilities	O	X			6705	N/A	N/A
18	Central Vermont P.S. Co.	O	X			10000	N/A	N/A
19	Com. Electric - Canal	O				4000	N/A	N/A
20								
21								
22	Purchased Power Used at Power Plant							
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PURCHASED POWER (Account 555) - Continued
(except interchange power)

4. If receipt of power is at a substation indicate ownership in column (e), thus: respondent owned or leased, RS; seller owned or leased, SS.
5. If a fixed number of kilowatts of maximum demand is specified in the power contract as a basis of billing, this number should be shown in column (f). The number of kws of maximum demand to be shown in columns (g) and (h) should be actual based on monthly readings and should be furnished whether or not used in the determination of demand charges. Show in column (i) type of demand reading (instantaneous), 15, 30, or 60 minutes integrated.
6. The number of kwhs purchased should be the quantities shown by the power bills.
7. Explain any amount entered in column (n) such as fuel and other adjustments. Amounts shown in column (n) are decommissioning charges.

Type of Demand Reading (i)	Voltage at Which Delivered (j)	Kilowatt-hours (k)	(l)	Energy (m)	Charges (n)	Total (o)	Cost per KWH (Cents) (0.0000) (p)	Line No.
NA	115 kv	14,268,800	$1,264,997	$75,000	$66,871	$1,406,868	9.8597	1
NA	115 kv	4,798,886	$142,621	$25,042	$13,323	$180,986	3.7714	2
NA	115 kv	9,846,174	$192,349	$46,185	$19,991	$258,525	2.6256	3
NA	115 kv	1,371,719	$99,762	$36,526	$0	$136,288	9.9356	4
NA	115 kv	16,965,200	$615,326	$17,999	$0	$633,325	3.7331	5
NA	115 kv	8,726,104	$141,622	$182,751	$0	$324,373	3.7173	6
NA	115 kv	5,477,170	$493,850	$25,140	$0	$518,990	9.4755	7
NA	115 kv	4,818,304	$343,043	$21,384	$0	$364,427	7.5634	8
NA	115 kv	11,369,921	$1,100,657	$68,296	$0	$1,168,953	10.2811	9
NA	115 kv	1,266,355	$139,711	$7,761	$0	$147,472	11.6454	10
NA	115 kv	86,098,030	$11,697,283	$616,050	$0	$12,313,333	14.3015	11
NA	115 kv	3,445,125	$309,368	$105,919	$0	$415,287	12.0543	12
NA	115 kv	17,814,326	$114,847	$0	$0	$114,847	0.6447	13
NA	115 kv	2,156,053	$0	$176,307	$0	$176,307	8.1773	14
NA	115 kv	14,536,007	$43,440	$353,960	$0	$397,400	2.7339	15
NA	115 kv	2,100,000	$0	$48,300	$0	$48,300	2.3000	16
NA	115 kv	14,616,000	$41,225	$309,288	$0	$350,513	2.3981	17
NA	115 kv	23,345,050	$146,451	$525,504	$0	$671,955	2.8784	18
NA	115 kv	2,520,070	$12,429	$56,457	$0	$68,886	2.7335	19
								20
CHARGED TO	ACCOUNT 549	(1,373,604)			($30,447)	($30,447)		21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
	TOTALS	244,165,690	$16,898,981	$2,697,869	$69,738	$19,666,588	8.0546	42

INTERCHANGE POWER (Included in Account 555)

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

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

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

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

Line No.	Name of Company (a)	Interchange Across State Lines (b)	Point of Interchange (c)	Voltage at Which Interchanged (d)	Kilowatt-Hours: Received (e)	Kilowatt-Hours: Delivered (f)	Kilowatt-Hours: Net Difference (g)	Amount of Settlement (h)
1	NEPEX		Hudson-Marlboro Town Line	115 KV	82,096,030	5,003,020	77,093,010	$2,110,421.86
2	USED AS STATION POWER AND CHARGED TO (549)				(365,135)		(365,135)	($12,359.32)
3								
4								
5								
6								
7								
8								
9								
10								
11								
12				TOTALS	81,730,895	5,003,020	76,727,875	$2,098,062.54

B. Details of Settlement for Interchange Power

Line No.	Name of Company (i)	Explanation (j)		Amount (k)
13	NEPEX	Energy Received by H.L.& P.	-Economy	$2,162,248.21
14			-Scheduled Outage	$67,767.21
15			-Unscheduled Outage	$161,086.15
16			-Deficiency	$0.00
17		Energy Dollars from NEPOOL		($147,501.38)
18		Quebec Net Savings Fund		($58,377.12)
19		NEPOOL Savings		($158,735.95)
20		NEPOOL Expenses		$68,286.22
21		Other		$15,648.52
			TOTAL	$2,110,421.86

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)			Kilowatt-hours (b)
1	**SOURCES OF ENERGY**			
2	Generation (excluding station use):			
3	Steam			0
4	Nuclear			4,179,752
5	Hydro			0
6	Other (DIESEL)			4,257,600
7	Total Generation			8,437,352
8	Purchases			244,165,690
9		In (gross)	81,730,895	* * * * *
10	Interchanges	Out (gross)	5,003,020	* * * * *
11		Net (kwh)		76,727,875
12		Received		
13	Transmission for/by others (wheeling)	Delivered		
14		Net (kwh)		
15	**TOTAL**			329,330,917
16	**DISPOSITION OF ENERGY**			
17	Sales to ultimate consumers (including interdepartmental sales)			306,557,493
18	Sales for resale			279,800
19	Energy furnished without charge			0
20	Energy used by the company (excluding station use):			315,086
21	Electric department only			
22	Energy losses:			
23	Transmission and conversion losses		11,671,356	
24	Distribution losses		8,588,821	
25	Unaccounted for losses		1,918,361	
26	Total energy losses			22,178,538
27	Energy losses as percent of total on line 15	6.7344%		
28			**TOTAL**	329,330,917

MONTHLY PEAKS AND OUTPUT

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

Line No.	Month (a)	Kilowatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (kwh) (See Instr. 4) (g)
29	January	49,400	THURSDAY	27	9:00	60 Min.	28,705,900
30	February	46,400	FRIDAY	11	9:00	60 Min.	25,704,151
31	March	44,900	WEDNESDAY	2	9:00	60 Min.	27,724,124
32	April	42,800	WEDNESDAY	13	11:00	60 Min.	25,066,293
33	May	43,900	MONDAY	23	14:00	60 Min.	28,894,305
34	June	52,100	FRIDAY	17	16:00	60 Min.	25,401,314
35	July	55,000	THURSDAY	21	16:00	60 Min.	31,566,970
36	August	53,200	THURSDAY	4	15:00	60 Min.	29,287,034
37	September	44,700	TUESDAY	13	15:00	60 Min.	26,220,601
38	October	41,400	MONDAY	31	18:00	60 Min.	26,440,798
39	November	45,000	MONDAY	28	18:00	60 Min.	26,376,976
40	December	47,500	MONDAY	12	18:00	60 Min.	27,942,451
41						TOTAL	329,330,917

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

1. Large stations for this purpose of this schedule are steam and h stations of 2,699 Kw* or more of installed capacity and other station 500 Kw* of more of installed capacity (name plate ratings). (*10,00 and 2,600 Kw, respectively, if annual electric operating revenue of r spondent are $25,000,000 or more.)
2. If any plant is leased, operated under a license from the Federa Power Commission, or operated as a joint facility, indicate such fact
4. If peak demand for 60 minutes is not available, give that which is available, specifying period.
5. If a group of employees attends more than one generating station, report on line 11 the approximate average number of employees assignable to each station.
6. If gas is used and purchased on a therm basis, the B.t.u. content of the gas should be given and the quantity of fuel converted to cy. ft.

Line No.	Item (a)	Plant Cherry St. Sta.	Plant HLP Peaking	Plant (d)
1	Kind of plant (steam, hydro, int. comb., gas turbine)	Int. Comb.	Int. Comb.	
2	Type of plant construction (conventional, out-door, boiler, full outdoor, etc.)	Conventional	Conventional	
3	Year originally constructed	1897	1962	
4	Year last unit was installed	1972	1962	
5	Total installed capacity (maximum generator name plate ratings in kw)	16,150*	4,400	
6	Net peak demand on plant-kilowatts (60 min.)	15.2	4.4	
7	Plant hours connected to load	455	312	
8	Net continuous plant capability, kilowatts:			
9	(a) When not limited by condensed water	15,200	4,400	
10	(b) When limited by condensed water	15,200	4,400	
11	Average number of employees	12		
12	Net generation, exclusive of station use	3,360,672	896,928	
13	Cost of plan (omit cents)			
14	Land and land rights	$5,500		
15	Structures and improvements	$332,768		
16	Reservoirs, dams and waterways			
17	Equipment costs	$3,117,779	712,054	
18	Roads, railroads and bridges			
19	Total Cost	$3,456,047	712,054	
20	Cost per kw of installed capacity	227	162	
21	Production expenses:			
22	Operation supervision and engineering	$27,089.19		
23	Station labor	$173,322.59		
24	Fuel	$161,738.05		
25	Supplies and expenses, including water	$73,275.94		
26	Maintenance	$184,981.54		
27	Rents	$0.00		
28	Steam from other sources	$0.00		
29	Steam transferred - Credit	$0.00		
30	Total production expenses	$620,407.31		
31	Expenses per net KWH (5 places)	$0.14572		
32	Fuel: kind	#2 Diesel	Natural Gas	
33	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-M cu. ft.) (Nuclear, indicate)	42 Gal	M Cu Ft	
34	Quantity (units) of fuel consumed	2,571	32,765	
35	Average heat content of fuel (B.t.u. per lb. of coal, per gal. of oil, or per cu. ft. of gas)	140,000 Btu	910 BTU	
36	Average cost of fuel per unit, del. f.o.b plant		$2.94548	
37	Average cost of fuel per unit consumed	$25.3711	$2.94548	
38	Average cost of fuel consumed per million B.t.u	$4.31414	$3.23679	
39	Average cost of fuel consumed per kwh net gen.	$0.03799		
40	Average B.t.u. per kwh net generation	10,554		
41				
42				

SEABROOK STATION UNIT # 1
ELECTRIC GENERATING PLANT STATISTICS

YEAR ENDING DECEMBER 31, 1994

DESCRIPTION	UNIT 1 VALUE
Kind of Plant	Nuclear
Type of Plant Construction	Fully Contained
Year Originally Constructed	1990
Year Last Unit Was Installed	1990
Total Installed Capacity	1197 MW
Net Peak Demand on Plant	1157 MW
Plant Hours Connected to Load	5467
Net Continuous Plant Capability	
a: When Not Limited by Condenser Water	1150
b: When Limited by Condenser Water	1150
Average Number of Employees	942
Net Generation Exclusive of Plant Use (KWH)	6,203,498,000
Fuel: Kind	Nuclear
Unit	Grams
Quantity of Fuel Burned	1,017,066
Average Heat Content of Fuel Burned	6.18x 10^7 BTU/Gr
Average BTU per KWH Net Generation	10,125.5 BTU

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

547 as shown on line 24.

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

9. If any plant is equipped with combinations of steam, hydro, internal combustion engine or gas turbine equipment, each should be rep a operation with a conventional steam unit, the gas turbine should be i

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

Plant (e)	Plant (f)	Plant (g)	Plant (h)	Plant (i)	Plant (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
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						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

STEAM GENERATING STATIONS

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

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

*Indicate reheat boilers thusly, 1050/1000

STEAM GENERATING STATIONS - Continued

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

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

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

Turbine-Generators*

Year Installed (h)	Type~ (i)	Steam Pressure at Throttle p.s.i.g (j)	R.P.M. (k)	Name Plate Rating in Kilowatts: At Minimum Hydrogen Pressure (l)	Name Plate Rating in Kilowatts: at Maximum Hydrogen Pressure (m)	Hydrogen Pressure~~ Min. (n)	Hydrogen Pressure~~ Max. (o)	Power Factor (p)	Voltage K.v.~~~ (p)	Station Capacity Maximum Name Plate Rating~~~~ (r)	Line No.
											1
											2
											3
											4
											5
											6
											7
											8
											9
											10
											11
											12
											13
											14
											15
											16
											17
											18
				N O T	A P P L	I C A	B L E				18
											20
											21
											22
											23
											24
											26
											27
											28
											29
											30
											31
											32
											33
											34
											35
											36
			TOTALS								37

Note References:

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

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

~~Designate air cooled generators

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

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

HYDROELECTRIC GENERATING STATIONS

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

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

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

HYDROELECTRIC GENERATING STATIONS (Continued)

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

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

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

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

COMBUSTION ENGINE AND OTHER GENERATING STATIONS
(except nuclear stations)

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

Line No.	Name of Station (a)	Location of Station (b)	Prime Movers: Diesel or Other Type Engine (c)	Name of Maker (d)	Year Installed (e)	2 or 4 Cycle (f)	Belted or Direct Connected (g)
1	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co.	1951	2	Direct
2	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co.	1955	2	Direct
3	Cherry St	Cherry Street, Hudson	Diesel	Norderg-MFG Co.	1960	2	Direct
4	Cherry St	Cherry Street, Hudson	Diesel	Cooper-Bessemer	1972	4	Direct
5							
6							
7							
8							
9							
10	Hudson Light	Cherry Street, Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
11	Peaking Plt.	Cherry Street, Hudson	Diesel	Fairbanks-Morse	1962	2	Direct
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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34							
35							
36							
37							
38							
39							

COMBUSTION ENGINE AND OTHER GENERATING STATIONS - Continued

(except nuclear stations)

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

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

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

Prime Movers _ Continued		Generators								
Rated hp. of Unit (h)	Total Rated hp. of Station Prime Movers (i)	Year Installed (j)	Voltage (k)	Phase (l)	Frequency or d.c. (m)	Name Plate Rating of Unit In Kilowatts (n)	Numbers of Units in Station (o)	Total Installed Generating Capacity In Kilowatts (name plate rating) (p)	Line No.
4,250	4,250	1951	4,160	3 ph	60 cyl.	3,300	1	3,000	1
5,100	9,350	1955	4,160	3 ph	60 cyl.	4,000	1	3,600	2
4,250	13,600	1943	4,160	3 ph	60 cyl.	3,250	1	3,000	3
7,760	21,360	1972	4,160	3 ph	60 cyl.	5,600	1	5,600	4
									5
									6
									7
									8
									9
3,168	3,168	1962	4,160	3 ph	60 cyl.	2,200	1	2,200	10
3,168	6,336	1962	4,160	3 ph	60 cyl.	2,200	1	2,200	11
									12
									13
									14
									15
									16
									17
									18
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									34
									35
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									37
									38
									38
					TOTALS	20,550	6	19,600	39

GENERATING STATION STATISTICS (Small Stations)

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

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

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

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

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

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

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

TRANSMISSION LINE STATISTICS

Report information concerning transmission lines as indicated below.

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

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

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	Voltage: Primary (c)	Voltage: Secondary (d)	Voltage: Tertiary (e)	Capacity of Substation In kva (In Service) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Cherry Street, Hudson, MA	Unattended	13800/	4160/	Not Brought	19,200	2	None	None	None	None
2		Distribution	8000	2400	Out						
3											
4											
5	Forest Avenue, Hudson, MA	Unattended									
6		13.8 Distribution									
7		& Diesel Tie	115 KV	13800/	NA	120,000	3	None	None	None	None
8		Tie with NEPCO		8000							
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30											
31											
32					TOTALS	139,200	5	None	None	None	None

OVERHEAD DISTRIBUTION LINES OPERATED

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

ELECTRIC DISTRIBUTION SERVICES, METERS AND LINE TRANSFORMERS

Line No.	Item	Electric Services	Number of Watt-Hour Meters	Line Transformers	
				Number	Total Capacity (kva)
16	Number at beginning of year	7,804	10,688	3,282	96,506.5
17	Added during year:				
18	Purchased		206	41	1,500.0
19	Installed	107			
20	Associated with utility plant acquired	None	None	None	None
21	Total additions	107	206	41	1,500.0
22	Reductions during year:				
23	Retirements	32	181	68	671.5
24	Associated with utility plant sold	None	None	None	None
25	Total reductions	32	181	68	671.5
26	Number at End of Year	7,879	10,713	3,255	97,335.0
27	In stock		519	391	17,397.0
28	Locked meters on customers' premises		None	None	None
29	Inactive transformers on system		None	None	None
30	In customers' use		10,169	2,856	79,804.0
31	In company's use		25	8	134.0
32	Number at End of Year		10,713	3,255	97,335.0

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

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

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

*Indicate number of conductors per cable.

Annual report of TOWN OF HUDSON LIGHT AND POWER DEPARTMENT Year ended December 31 1994 70A

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

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

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

*Indicate number of conductors per cable.

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

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

Line No.	Designation of Underground Distribution System (a)	Miles of Conduit Bank (All Sizes and Types) (b)	Underground Cable		Submarine Cable	
			Miles* (c)	Operating Voltage (d)	Feet* (e)	Operating Voltage (f)
1	Cranberry Lane, Hudson	0.24	0.24	13,800		
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33						
34	TOTALS	0.24	0.24		None	None

*Indicate number of conductors per cable.

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town (a)	Total (b)	Type: Incasdescent Municipal (c)	Incasdescent Other (d)	Mercury Vapor Municipal (e)	Mercury Vapor Other (f)	Fluorescent Municipal (g)	Fluorescent Other (h)	H. P. Sodium Municipal (i)	H. P. Sodium Other (j)
1	Hudson	1,925	388	15	901	225			270	126
2	Stow	75	4	2	6	32			20	11
3	Berlin	1	1							
4	Marlboro	4				1				3
5	Bolton	1				1				
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52	TOTAL	2006	393	17	907	259			290	140

RATE SCHEDULE INFORMATION

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

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

Date Effective	M.D.P.U. Number	Rate Schedule	Estimated Effect on Annual Revenues	
			Increases	Decreases
02/01/94	149	Domestic Rate "A"		$607,390
02/01/94	150	Commercial All Electric Rate "G"		$174,110
02/01/94	151	Commercial and Industrial Rate "D"		$3,305,786
02/01/94	152	Residential Water Heater Rate "E"		$141,184
02/01/94	153	Residential All Electric Rate "F"		$232,918
02/01/94	154	General or Commercial Rate "C"		$400
02/01/94	155	Street Lighting Schedule		$3,992
02/01/94	156	Service Charges	$5,100	

THIS RETURN IS SIGNED UNDER THE PENALTIES OF PERJURY

Mayor

Horst Huehmer

HORST HUEHMER *Manager of Electric Light*

Roland L. Plante

ROLAND L. PLANTE

Peter R. Keane

PETER R. KEANE

Weedon G. Parris Jr.

WEEDON G. PARRIS JR.

Selectmen or Members of the Municipal Light Board

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

ss 19

Then personally appeared

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

Notary Public or Justice of the Peace.

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EXTRACTS FROM CHAPTER 164 OF THE GENERAL LAWS AS AMENDED

SECTION 56. The Mayor of a city, or the selectmen or municipal light board, if any, of a town acquiring a gas or electric plant shall appoint a manager of municipal lighting who shall, under the direction and control of the mayor, selectmen or municipal light board, if any, and subject to this chapter, have full charge of the operation and management of the plant, the manufacture and distribution of gas or electricity, the purchase of supplies, the employment of agents and servants, the method, time, price, quantity and quality of the supply, the collection of bills, and the keeping of accounts. His compensation and term of office shall be fixed in cities by the city council and in towns by the selectmen or municipal light board, if any; and, before entering upon the performance of his official duties, he shall give bond to the city or town for the faithful performance thereof in a sum and form and with sureties to the satisfaction of the mayor, selectmen or municipal light board, if any, and shall, at the end of each municipal year, render to them such detailed statement of his doings and of the business and financial matters in his charge as the department may prescribe. All moneys payable to or received by the city, town, manager or municipal light board in connection with the operation of the plant, for the sale of gas or electricity or otherwise, shall be paid to the city or town treasurer. All accounts rendered to or kept in the gas or electric plant of any city shall be subject to the inspection of the city auditor or officer having similar duties, and in towns they shall be subject to the inspection of the selectmen. The auditor or officer having similar duties, or the selectmen, may require any person presenting for settlement an account or claim against such plant to make oath before him or them, in such form as he or they may prescribe, as to the accuracy of such account or claim. The wilful making of a false oath shall be punishable as perjury. The auditor or officer having similar duties in cities, and the selectmen in towns, shall approve the payment of all bills or pay rolls of such plants before they are paid by the treasurer, and may disallow and refuse to approve for payment, in whole or in part, any claim as fradulent, unlawful or excessive; and in that case the auditor or officer having duties, or the selectmen, shall file with the city or town treasurer a written statement of the reasons for the refusal; and the treasurer shall not pay any claim or bill so disallowed. This section shall not abridge the powers conferred on town accountants by sections fifty-five to sixty-one, inclusive, of chapter forty-one. The manager shall at any time, when required by the mayor, selectmen, municipal light board, if any, or department, make a statement to such officers of his doings, business, receipts, disbursements, balances, and of the indebtedness of the town in his department.

SECTION 57. At the beginning of each fiscal year, the manager of municipal lighting shall furnish to the mayor, selectmen or municipal light board, if any, an estimate of the income from sales of gas and electricity to private consumers during the ensuing fiscal year, and of the expense of the plant during said year, meaning the gross expenses of operation, maintenance and repair, the interest on the bonds, notes or certificates of indebtedness issued to pay for the plant, an amount for depreciation equal to three per cent of the cost of the plant exclusive of land and any water power appurtenant thereto, or such smaller or larger amount as the department may approve, the requirements of the sinking fund or debt incurred for the plant, and the loss, if any, in the operation of the plant during the preceding year, and of the costs, as defined in section 58, of the gas and electricity to be used by the town. The town shall include in its annual appropriations and in the tax levy not less than the estimated cost of the gas and electricity to be used by the town as above defined and estimated. By cost of the plant is intended the total amount expended on the plant to the beginning of the fiscal year for the purpose of establishing, purchasing, extending or enlarging the same. By loss in operation is intended the difference between the actual income from private consumers plus the appropriations for maintenance for the preceding fiscal year and the actual expense of the plant, reckoned as above, for that year in case such expenses exceeded the amount of such income and appropriation. The income from sales and the money appropriated as aforesaid shall be used to pay the annual expense of the plant, defined as above, for the fiscal year, except that no part of the sum therein included for depreciation shall be used for any other purpose than renewals in excess of ordinary repairs, extensions, reconstruction, enlargements and additions. The surplus, if any, of said annual allowances for depreciation after making the above payments shall be kept as a separate fund and used for renewals other than ordinary repairs, extensions, reconstructions, enlargements and additions in succeeding years; and no debt shall be incurred under section forty for any extension, reconstruction or enlargements of the plant in excess of the amount needed therefor in addition to the amount then on hand in said depreciation fund. Said depreciation fund shall be kept and managed by the town treasurer as a separate fund, subject to appropriation by the city council or selectmen or municipal light board, if any, for the foregoing purpose. So much of said fund as the department may from time to time approve may also be used to pay notes, bonds or certificates of indebtedness issued to pay for the cost of reconstruction or renewals in excess of ordinary repairs, when such notes, bonds or certificates of indebtedness become due. All appropriations for the plant shall be either for the annual expense defined as above, or for extensions, reconstruction, enlargements or additions; and no appropriation shall be used for any purpose other than that stated in the vote making the same. No bonds, notes or certificates of indebtedness shall be issued by a town for the annual expenses as defined in this section.

SECTION 63. A town manufacturing or selling gas or electricity for lighting shall keep records of its work and doings at its manufacturing station, and in respect to its distributing plant, as may be required by the department. It shall install and maintain apparatus, satisfactory to the department, for the measurement and recording of the output of gas and electricity, and shall sell the same by meter to private consumers when required by the department, and, if required by it, shall measure all gas or electricity consumed by the town. The books, accounts and returns shall be made and kept in a form prescribed by the department, and the accounts shall be closed annually on the last day of the fiscal year of such town, and a balance sheet of that date shall be taken therefrom and included in the return to the department. The mayor, selectmen or municipal light board and manager shall, at any time, on request, submit said books and accounts to the inspection of the department and furnish any statement or information required by it relative to the condition, management and operation of said business. The department shall, in its annual report, describe the operation of the several municipal plants with such detail as may be necessary to disclose the financial condition and results of each plant; and shall state what towns, if any, operating a plant have failed to comply with this chapter, and what towns, if any, are selling gas or electricity with the approval of the department at less than cost. The mayor, or selectmen, or municipal light board, if any, shall annually, on or before such date as the department fixes, make a return to the department, for the preceding fiscal year, signed and sworn to by the mayor, or by a majority of the selectmen or municipal light board, if any, and by the manager, stating the financial condition of said business, the amount of authorized and existing indebtedness, a statement of income and expenses in such detail as the department may require, and a list of its salaried officers and the salary paid to each. The mayor, the selectmen or the municipal light board may direct any additional returns to be made at such time and in such detail as he or they may order. Any officer of a town manufacturing or selling gas or electricity for lighting who, being required by this section to make an annual return to the department, neglects to make such annual return shall, for the first fifteen days or portion thereof during which such neglect continues, forfeit five dollars a day; for the second fifteen days or any portion thereof, ten dollars a day; and for each day thereafter not more than fifteen dollars a day. Any such officer who unreasonably refuses or neglects to make such return shall, in addition thereto, forfeit not more than five hundred dollars. If a return is defective or appears to be erroneous, the department shall notify the officer to amend it within fifteen days. Any such officer who neglects to amend said return within the time specified, when notified to do so, shall forfeit fifteen dollars for each day during which such neglect continues. All forfeitures incurred under this section may be recovered by an information in equity brought in the supreme judicial court by the attorney general, at the relation of the department, and when so recovered shall be paid to the commonwealth.

SECTION 69. The supreme judicial court for the county where the town is situated shall have jurisdiction on petition of the department or of twenty taxable inhabitants of the town to compel the fixing of prices by the town in compliance with sections fifty-seven and fifty-eight, to prevent any town from purchasing, operating or selling a gas or electric plant in violation of any provision of this chapter, and generally to enforce compliance with the terms and provisions thereof relative to the manufacture or distribution of gas or electricity by a town.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 1994

OR

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

For the transition period from _______ to _____

Commission File Number 1-6788

THE UNITED ILLUMINATING COMPANY

(Exact name of registrant as specified in its charter)

Connecticut	**06-0571640**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
157 Church St., New Haven, Connecticut	**06506**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 203-499-2000

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: Common Stock, no par value

---

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

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

The aggregate market value of the registrant's voting stock held by non-affiliates on February 28, 1995 was $465,741,221, computed on the basis of the average of the high and low sale prices of said stock reported in the listing of composite transactions for New York Stock Exchange listed securities, published in The Wall Street Journal on March 1, 1995.

The number of shares outstanding of the registrant's only class of common stock, as of February 28, 1995, was 14,086,691.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Part of this Form 10-K into which document is incorporated
Definitive Proxy Statement, dated March 29, 1995, for Annual Meeting of the Shareholders to be held on May 17, 1995.	III

THE UNITED ILLUMINATING COMPANY
FORM 10-K
December 31, 1994

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GLOSSARY

Certain capitalized terms used in this Annual Report have the following meanings, and such meanings shall apply to terms both singular and plural unless the context clearly requires otherwise:

"AFUDC" means allowance for funds used during construction.

"Company" or "UI" means The United Illuminating Company.

"CSC" means the Connecticut Siting Council.

"Connecticut Yankee" means the Connecticut Yankee Atomic Power Company.

"Connecticut Yankee Unit" means the nuclear electric generating unit owned and operated by Connecticut Yankee.

"DEP" means the Connecticut Department of Environmental Protection.

"DOE" means the United States Department of Energy.

"DPUC" means the Connecticut Department of Public Utility Control.

"EPA" means the United States Environmental Protection Agency.

"FERC" means the United States Federal Energy Regulatory Commission.

"FCA" means fossil fuel adjustment clause.

"LLW" means low-level radioactive wastes.

"Millstone Unit 3" means the nuclear electric generating unit located in Waterford, Connecticut, which is jointly owned by UI and thirteen other New England electric utilities.

"NDFC" means the Nuclear Decommissioning Finance Committee.

"NEPOOL" means the New England Power Pool.

"NRC" means the United States Nuclear Regulatory Commission.

"PCBs" means polychlorinated biphenyls.

"Preferred Stock" means capital stock of the Company having preferential dividend and liquidation rights over shares of the Company's other classes of capital stock.

"RCI" means Research Center, Inc., a wholly-owned subsidiary of UI.

"RCRA" means the federal Resource Conservation and Recovery Act.

"Seabrook Unit 1" means nuclear generating unit No. 1 located in Seabrook, New Hampshire, which is jointly owned by UI and eleven other New England electric utilities.

"SEC" means Securities and Exchange Commission.

GLOSSARY (continued)

"SO_2" means sulfur dioxide.

"SPI" means Souwestcon Properties, Inc., a wholly-owned subsidiary of URI.

"TSCA" means the federal Toxic Substances Control Act.

"UEI" means United Energy International, Inc., a wholly-owned subsidiary of UI.

"UI" or "Company" means The United Illuminating Company.

"URI" means United Resources, Inc., a wholly-owned subsidiary of UI.

PART I

Item 1. Business.

GENERAL

The United Illuminating Company is an operating electric public utility company, incorporated under the laws of the State of Connecticut in 1899. It is 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 population of this area is approximately 711,000 or 22% of the population of the State. The service area, largely urban and suburban in character, includes the principal cities of Bridgeport (population 142,000) and New Haven (population 130,000) 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. Of the Company's 1994 retail electric revenues, approximately 41% was derived from residential sales, 40% from commercial sales, 17% from industrial sales and 2% from other sales.

UI has three wholly-owned subsidiaries. Research Center, Inc. (RCI) has been formed to participate in the development of one or more regulated power production ventures, including possible participation in arrangements for the future development of independent power production and cogeneration facilities. United Energy International, Inc. (UEI) was formed to facilitate participation in a joint venture relating to power production plants abroad. United Resources, Inc. (URI) serves as the parent corporation for several unregulated businesses, each of which is incorporated separately to participate in business ventures that will complement and enhance UI's electric utility business and serve the interests of the Company and its shareholders and customers.

Four wholly-owned subsidiaries of URI have been incorporated. Souwestcon Properties, Inc. (SPI) participated as a 25% partner in the ownership of a medical hotel building in New Haven, which has recently been sold. SPI no longer owns any property and is currently inactive. A second wholly-owned subsidiary of URI is Thermal Energies, Inc., which 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 37% 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 and industrial facilities. A fourth URI subsidiary, American Payment Systems, Inc., manages agents and equipment for electronic data processing of bill payments made by customers of utilities, including UI, at neighborhood businesses. In addition to these subsidiaries, URI also has a 90% ownership interest in Ventana Corporation, which offers energy conservation engineering and project management services to governmental and private institutions.

The Board of Directors of the Company has authorized the investment of a maximum of $18.0 million, in the aggregate, of the Company's assets in all of URI's ventures, UEI and RCI, and, at December 31, 1994, approximately $14.5 million had been so invested.

FRANCHISES, REGULATION AND COMPETITION

Franchises

Subject to the power of alteration, amendment or repeal by the Connecticut legislature, and subject to certain approvals, permits and consents of public authorities and others prescribed by statute, the Company has valid franchises to engage in the production, purchase, transmission, distribution and sale of electricity in the area served by it, the right to erect and maintain certain facilities on public highways and grounds, and the power of eminent domain.

Regulation

The Company is subject to regulation by the Connecticut Department of Public Utility Control (DPUC), which has jurisdiction with respect to, among other things, retail electric service rates, accounting procedures, certain dispositions of property and plant, mergers and consolidations, the issuance of securities, certain standards of service, management efficiency, operation and construction, and the location and construction of certain electric facilities. See "Rates". The DPUC consists of five Commissioners, appointed by the Governor of Connecticut with the advice and consent of both houses of the Connecticut legislature.

The location and construction of certain electric facilities is also subject to regulation by the Connecticut Siting Council with respect to environmental compatibility and public need. See "Environmental Regulation".

UI is a "public utility" within the meaning of Part II of the Federal Power Act and is subject to regulation by the Federal Energy Regulatory Commission (FERC), which has jurisdiction with respect to interconnection and coordination of facilities, wholesale electric service rates and accounting procedures, among other things. See "Arrangements with Other Utilities".

The Company is a holder of licenses under the Atomic Energy Act of 1954, as amended, and, as such, is subject to the jurisdiction of the United States Nuclear Regulatory Commission (NRC), which has broad regulatory and supervisory jurisdiction with respect to the construction and operation of nuclear reactors, including matters of public health and safety, financial qualifications, antitrust considerations and environmental impact. Connecticut Yankee Atomic Power Company (Connecticut Yankee) is also subject to this NRC regulatory and supervisory jurisdiction. See Item 2. Properties - "Nuclear Generation".

The Company is subject to the jurisdiction of the New Hampshire Public Utilities Commission for limited purposes in connection with its ownership interest in Seabrook Unit 1.

Competition

The electric utility industry has become, and can be expected to be, increasingly competitive, due to a variety of economic, regulatory and technological developments; and UI is exposed to competitive forces in varying degrees.

Although UI has not historically been a major wholesale supplier of bulk electric power (power sold to other utilities), it has marketed generating capacity and energy aggressively in recent years, seeking to sell outside its service territory the power it produces in excess of the present needs of its own customers that became available when Seabrook Unit 1 commenced operating in 1990. Due to a general oversupply of power in the New England region and the region's slow economic growth, the Company's wholesale sales efforts have faced increasing competition; and new wholesale sales opportunities are expected to remain relatively weak during the near term. Moreover, competition in this market can be expected to increase by reason of the federal Energy Policy Act of 1992, which was designed to foster competition in the wholesale market by facilitating the ownership and operation of independently-owned generating facilities and authorizing the FERC to order electric utilities to furnish transmission service to the owners of these generating facilities. Competition may also increase in the wholesale power market due to the entry of brokers and marketers, who buy and sell generating capacity and energy without owning or operating any generating or transmission facilities.

In UI's principal market, retail sales of electricity in the Company's franchised service territory, competitive pressures are rising from several sources. Industrial and large commercial customers may have the ability to own and operate facilities that generate their own electric energy requirements. If these facilities satisfy certain statutory requirements, UI can be required to purchase their output at UI's avoided cost. These customers may also substitute natural gas or oil for electricity as fuel for heating and cooling purposes, and industrial customers may have the option of relocating their facilities to a lower-cost environment. As a result of these pressures, and with the approval of the DPUC, UI offers special rate and service agreements to induce industrial and large commercial customers to remain on the Company's system. However, to the extent that the Company loses revenues from customers leaving the system or paying for service under special rate or service agreements, the Company's only opportunity to replace such revenues will be through increased wholesale sales and retail sales growth. The Company is not capitalizing these "lost" revenues for future rate recovery and has stated publicly that it does not plan to seek retail rate increases for the foreseeable future.

The legislatures and regulatory commissions in several states have considered or are considering "retail wheeling." This, in general terms, means the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the utility's own service territory. A retail wheeling requirement would have the effect of permitting retail customers to purchase electric capacity and energy, at the election of such customers, from the electric utility in whose service area they are located or from any other electric utility or independent power producer. The DPUC has completed a proceeding that investigated whether retail wheeling should be permitted in Connecticut. Among other things, the DPUC concluded that the introduction of open competition for retail sales is not in the best interests of the affected constituencies, State energy policy, or the economy of the State of Connecticut. Nevertheless, the DPUC recommended that Connecticut utilities should prepare for the eventuality of either retail wheeling or some other form of competition that is more intense than the current franchise framework.

RATES

The Company's retail electric service rates are subject to regulation by the DPUC.

UI's present general retail rate structure consists of various rate and service classifications covering residential, commercial, industrial and street lighting services.

On December 16, 1992, the DPUC approved levelized rate increases of 2.66% ($15.8 million) in 1993 and 2.66% (an additional $17.3 million) in 1994, including allowed conservation and load management program revenue increases. However, the Company has realized increased revenues of $12.1 million and $12.5 million in 1993 and 1994, respectively, as a result of these rate increases.

Utilities are entitled by Connecticut law to revenues sufficient to allow them to cover their operating and capital costs, to attract needed capital and maintain their financial integrity, while also protecting the public interest. Accordingly, the DPUC's 1992 rate decision authorized a return on equity of 12.4% for ratemaking purposes. However, the Company may earn up to 1% above this level before a mandatory review is required by the DPUC.

The Company is allowed revenue increases for conservation and load management expenditures through a Conservation Adjustment Mechanism (CAM) in its retail rates, and accordingly expects a revenue increase in 1995 of $6 million, or 1%, through operation of the CAM. Except for CAM revenue increases, the Company has stated publicly that it does not plan to seek any retail rate increases for the foreseeable future.

Since January 1971, UI has had a fossil fuel adjustment clause (FCA) in virtually all of its retail rates. The DPUC is required by law to convene an administrative proceeding prior to approving FCA charges or credits for each month. The law permits automatic implementation of the charges or credits if the DPUC fails to act within five days of the administrative proceeding, although all such charges and credits are also subject to further review and appropriate adjustment by the DPUC at public hearings required to be held at least every three months. The DPUC has made no material changes in UI's FCA charges and credits as the result of any of these proceedings or hearings.

FINANCING

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

	1995	1996	1997	1998	1999
			(000's)		
Capital Expenditure Program	$ 75,840	$76,176	$ 51,816	$ 60,768	$ 92,880
Long-term Debt Maturities	97,000	-	50,000	100,000	100,000
Mandatory Redemptions/Repayments	66,133	12,770	15,171	15,562	15,988
Total Capital Requirements	$238,973	$88,946	$116,987	$176,330	$208,868

The Company presently estimates that its cash on hand and temporary cash investments at the beginning of 1995, totaling $11.4 million, and its projected net cash provided by operations, less dividends, of $105.3 million, will be sufficient to fund the Company's entire capital expenditure program of $75.8 million and $40.9 million of the $163.1 million necessary to satisfy the 1995 requirements for long-term debt maturities and mandatory long-term debt redemptions and repayments. The Company presently estimates that its projected net cash provided by operations, less dividends, of $97.7 million, will be sufficient to fund the Company's entire capital expenditure program of $76.2 million and all of the Company's 1996 requirements for mandatory redemptions and repayments of $12.8 million. The Company presently estimates that its projected net cash provided by operations, less dividends, of $282.0 million, will be sufficient to fund the Company's entire capital expenditure program of $205.5 million and $76.5 million of the $296.7 million necessary to satisfy the 1997 through 1999 requirements for long-term debt maturities and mandatory long-term debt redemptions and repayments.

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 $225 million revolving credit agreement with a group of banks, described below, the Company expects to be able to satisfy its external financing needs by issuing common stock, preferred stock and additional short-term and long-term debt, although the continued availability of these methods of financing will be dependent on many factors, including conditions in the securities markets, economic conditions, and the level of the Company's income and cash flow.

In January 1994, the Company repaid $55.3 million principal amount of maturing 10.32% First Mortgage Bonds of Bridgeport Electric Company, a wholly-owned subsidiary of the Company that was subsequently merged with and into the Company, and a $5 million 13.1% term loan. These repayments were made with a portion of the net proceeds from the issuance and sale, in December 1993, of $100 million five-year and one month Notes at a coupon rate of 6.20%.

On September 12, 1994, the Company repaid at maturity $30 million principal amount of 7.62% Notes. In addition, on November 1, 1994, December 2, 1994 and January 17, 1995, the Company repaid at maturity $13 million, $10 million and $50 million principal amounts of 7.20%, 6.82% and 6.0% Notes, respectively.

On October 1, 1994 and December 1, 1994, the Company redeemed the remaining $110,000 and $3,830,000 principal amounts of 14 1/2% 1984 Series, and 14 1/2% 1984 Series B, Pollution Control Revenue Bonds, respectively, at a 3% premium.

On January 17, 1995 and February 15, 1995, the Company repaid $55.3 million and $10.8 million principal amounts of maturing 10.32% and 9.44% First Mortgage Bonds of Bridgeport Electric Company, a wholly-owned subsidiary of the Company that was merged with and into the Company in September of 1994.

On August 18, 1994, United Capital Funding Partnership L.P. ("United Capital"), a special purpose limited partnership in which the Company owns all of the general partner interests, was formed for the sole purpose of issuing its limited partner interests, represented by Preferred Capital Securities ("Capital Securities"), and lending the proceeds thereof to the Company in return for Junior Subordinated Deferrable Interest Debentures ("Subordinated Debentures"). United Capital and the Company have registered $100 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. The Company has also registered $200 million principal amount of Notes for sale to the public from time to time, in one or more series, under the Securities Act of 1933.

The Company has a revolving credit agreement with a group of banks, which currently extends to December 14, 1995. The borrowing limit of this facility is $225 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, 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. 1994, the Company had $67 million in short-term borrowings outstanding under this facility.

In January 1995, the Company entered into interest rate cap agreements, with several banks, to protect $100 million of its short-term debt from increases in short-term interest rates. The agreements provide that if the LIBOR (London Interbank Offering Rate), for one-month borrowings, exceeds 8.50% on the 17th of any month during the period beginning February 17, 1995 and ending January 17, 1997, the banks will pay to the Company the difference between that LIBOR and 8.50%, multiplied by $100 million, for the subsequent one-month period.

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, 1994, this coverage ratio was 2.86.

The Company has a Fossil Fuel Supply Agreement with a financial institution providing for financing up to $37.5 million in fossil fuel purchases. Under this agreement, the financing entity acquires and stores natural gas, coal and fuel oil for sale to the Company, and the Company purchases 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 1996. At December 31, 1994, approximately $10.7 million of fossil fuel purchases were being financed under this agreement.

The Company's Preferred Stock provisions prohibit the issuance of additional Preferred Stock unless the Company's after-tax income for a period of twelve consecutive months ending not more than 90 days prior to such issuance is at least one and one-half times the aggregate of annual interest charges on all indebtedness and annual dividends on all Preferred Stock to be outstanding. The Preferred Stock provisions also prohibit any increase in long-term indebtedness unless the Company's after-tax income for a period of twelve consecutive months ending not more than 90 days prior to such increase is at least twice the annualized interest charges on all long-term indebtedness to be outstanding.

The provisions of the financing documents under which the Company leases a portion of its entitlement in Seabrook Unit 1 from an owner trust established for the benefit of an institutional investor presently require UI to maintain its consolidated annual after-tax cash earnings available for the payment of interest at a level that is at least one and one-half times the aggregate interest charges paid on all indebtedness outstanding during the year.

On the basis of the formulas contained in the Preferred Stock provisions and the Seabrook Unit 1 lease financing documents, the coverages for each of the five years ended December 31, 1994 are set forth below.

	Preferred Stock Provisions		Seabrook Lease Provisions
Year	Preferred Stock	Long-term Indebtedness	Earnings/Interest Ratio
1990	3.38	3.84	1.72
1991	3.38	3.77	2.20
1992	3.23	3.88	2.41
1993	3.33	3.67	2.59
1994	2.72	3.14	2.86

The Company has a 5.45% participating share in Phase II of the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. See "Arrangements with Other Utilities - Hydro-Quebec". As a participant, the Company is obligated to furnish a guarantee for its participating share of the debt financing for Phase II of the facility. Currently, the Company's guarantee liability for this debt amounts to approximately $9.2 million.

The Company has a 9.5% common stock ownership share in Connecticut Yankee Atomic Power Company, which owns and operates a nuclear electric generating station in Haddam Neck, Connecticut. Connecticut Yankee plans and implements a construction program that is essential to maintain its station as a dependable source of low-cost electric power in New England. In this regard, the Company is obligated to furnish 9.5% of Connecticut Yankee's capital requirements within specified limits. As a condition of the debt financing arrangements for Connecticut Yankee's construction program, the lenders from time to time have required guarantees from the shareowners of Connecticut Yankee, although no such guaranteed debt is currently outstanding.

FUEL SUPPLY

Fossil Fuel

The Company burns coal, residual oil and natural gas at its fossil fuel generating stations in Bridgeport and New Haven. During 1994, approximately 821,000 tons of coal, 2.3 million barrels of fuel oil and 506 million cubic feet of natural gas were consumed in the generation of electricity. The Company owns and leases fuel oil storage tanks at its major generating stations in Bridgeport and New Haven that have maximum capacities of approximately 680,000 and 650,000 barrels of oil, respectively. In addition, the Company maintains approximately a 45-day coal supply of 150,000 tons at its Bridgeport Harbor Station.

The Company has a fuel oil supply contract with the Tosco Corporation for the Company's New Haven and Bridgeport generating stations. The contract expires on September 30, 1995.

The Company burns coal at the largest generating unit at Bridgeport Harbor Station, which is also capable of burning oil, and has a coal supply contract with Pittston Coal Sales Company that extends until July 31, 2007, subject to earlier termination provisions.

The Company's New Haven Harbor Station has a dual-fuel capability of burning natural gas and oil. Under an agreement with Tenngasco, a division of Tenneco, the Company is obligated to burn approximately 6 billion cubic feet of gas per year, when offered by Tenngasco at a price that is competitive with oil. The natural gas burned by the Company during 1994 was not purchased pursuant to this agreement.

Nuclear Fuel

In addition to its common stock ownership in Connecticut Yankee, the Company holds ownership and leasehold interests in Seabrook Unit 1 and Millstone Unit 3, both of which are nuclear-fueled generating units. Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, enrichment of that gas and fabrication of the enriched hexafluoride into usable fuel assemblies.

After a region (approximately 1/5 to 1/3 of the nuclear fuel assemblies in the reactor at any time) of spent fuel is removed from a nuclear reactor, it is placed in temporary storage in a spent fuel pool at the nuclear station for cooling and ultimately is expected to be transported to permanent storage sites.

Based on information furnished by the utilities responsible for the operation of the units in which the Company is participating, there are outstanding contracts that cover uranium concentrate purchases for the Connecticut Yankee Unit and Millstone Unit 3 through 1995 and for Seabrook Unit 1 through 1999. In addition, there are outstanding contracts, to the extent indicated below, for conversion, enrichment and fabrication services for these units extending through the following years:

	Conversion to Hexafluoride	Enrichment	Fabrication
Connecticut Yankee Unit	1995	1999 (1)	1999 (2)
Millstone Unit 3	1995	1995 (1)	1997 (3)
Seabrook Unit 1	1999	2002	2007

(1) 70% of the enrichment requirements through 1998, and 50% through 1999, are covered under the present contract. Negotiations are in progress for the remaining uncontracted services through 2002.
(2) Negotiations are in progress that would extend the contract through 2007.
(3) The contract provides an option to extend fabrication services through 1999.

ARRANGEMENTS WITH OTHER UTILITIES

The Company, in cooperation with other privately and publicly owned New England electric utilities, established the New England Power Pool (NEPOOL) in 1971. The objectives of NEPOOL are: (a) to assure that the bulk power supply of New England and any adjoining areas served conforms to proper standards of reliability, (b) to attain maximum practicable economy, consistent with such proper standards of reliability, in such bulk power supply, and (c) to provide for equitable sharing of the resulting benefits and costs. These objectives are achieved through joint planning, central dispatching, cooperation in environmental matters, coordinated construction, operation and maintenance scheduling of electric generation and transmission facilities and through the provision for more effective coordination with other power pools and utilities situated in the United States and Canada. The agreement establishing NEPOOL is filed with the Federal Energy Regulatory Commission (FERC) and its provisions are subject to continuing FERC jurisdiction.

Operation, dispatching and coordination of planning of electric generating capacity for New England is done on a regular basis under NEPOOL. A central dispatching agency of NEPOOL, designated NEPEX, directs the operation and schedules the maintenance of the generating and transmission facilities of participating utilities and provides for coordination with other power pools and utilities.

The Company contributes to the financial support of certain 345 kilovolt transmission facilities that are a part of the New England transmission grid in connection with its participation in the ownership of Seabrook Unit 1 and Millstone Unit 3.

Hydro-Quebec

The Company is a participant in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. Phase II of this facility, in which UI has a 5.45% participating share, has increased the capacity of the intertie from 690 megawatts to a maximum of 2,000 megawatts. 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. See "Financing".

ENVIRONMENTAL REGULATION

The National Environmental Policy Act requires that detailed statements of the environmental effect of the Company's facilities be prepared in connection with the issuance of various federal permits and licenses, some of which are described below. Federal agencies are required by that Act to make an independent environmental evaluation of the facilities as part of their actions during proceedings with respect to these permits and licenses.

The federal Clean Water Act requires permits for discharges of effluents into navigable waters and requires that all discharges of pollutants comply with federally approved state water quality standards. The Connecticut Department of Environmental Protection (DEP) has adopted, and the federal government has approved, water quality standards for receiving waters in Connecticut. A joint federal and state permit system, administered by the DEP, has been established to assure that applicable effluent limitations and water quality standards are met in connection with the construction and operation of facilities that affect or discharge into these waters. The current discharge permit for New Haven Harbor Station was issued by the DEP on September 30, 1991. The discharge permits for Bridgeport Harbor, English and Steel Point Stations expired on February 25, 1992, May 15, 1992 and March 16, 1992, respectively. Applications for renewal of these permits were filed on August 23, 1991, November 14, 1991 and September 13, 1991, respectively, and the applications for English and Steel Point Stations have since been modified to reflect changes in the operating status of these generating facilities and changes in the permitting system. Some new permits have been issued for specific discharges and, although other new permits have not yet been issued, the Company has not been advised by the DEP that any of these facilities has a permitting problem. While renewal applications are pending, the terms of the expired permits continue in effect. The DEP has determined that the thermal component of the discharges at each of the Company's stations will not result in a violation of state water quality standards and that the location, design, construction and capacity of the cooling water intake structures reflect the best technology available, as defined by the federal Environmental Protection Agency (EPA). All discharge permits may be reopened and amended to incorporate more stringent standards and effluent limitations that may be adopted by federal and state authorities. Compliance with this permit system has necessitated substantial capital and operational expenditures by UI, and it is expected that such expenditures will continue to be required in the future. Although the magnitude of future expenditures cannot now be estimated accurately, the Company presently anticipates spending several million dollars during the next several years to consolidate and improve the wastewater collection and treatment system at Bridgeport Harbor Station.

Under the federal Clean Air Act, the EPA has promulgated national primary and secondary air quality standards for certain air pollutants, including sulfur oxides, particulate matter and nitrogen oxides. The DEP has adopted regulations for the attainment, maintenance and enforcement of these standards. In order to comply with these regulations, the Company is required to burn fuel oil with a sulfur content not in excess of 1%, and Bridgeport Harbor Unit 3 is required to burn a low-sulfur, low-ash content coal, the sulfur dioxide (SO_2) emissions from which are not to exceed 1.1 pounds of SO_2 per million BTU of heat input. Current air pollution regulations also include other air quality standards, emission performance standards and monitoring, testing and reporting requirements that are applicable to the Company's generating stations and further restrict the construction of new sources of air pollution or the modification of existing sources by requiring that both construction and operating permits be obtained and that a new or modified source will not cause or contribute to any violation of the EPA's national air quality standards or its regulations for the prevention of significant deterioration of air quality.

Amendments to the Clean Air Act in 1990 will require a significant reduction in nationwide SO_2 emissions by fossil fuel-fired generating units to a permanent total emissions cap in the year 2000. This reduction is to be achieved by the allotment of allowances to emit SO_2, measured in tons per year, to each owner of a unit, and requiring the owner to hold sufficient allowances each year to cover the emissions of SO_2 from the unit during that year. Allowances are transferable and able to be bought and sold. The Company believes that, under the allowances allocation formula, it will hold more than sufficient allowances to permit continued operation of its existing generating units without incurring substantial expenditures for additional SO_2 controls. The Company is marketing its surplus allowances, and has sold to a midwestern utility company an option to purchase a quantity of the Company's surplus allowances commencing in the year 2000. This sale has not had a significant impact on the Company's earnings.

The same 1990 Clean Air Act amendments also contain major new requirements for the control of nitrogen oxides that are applicable to generating units located in or near areas, such as UI's service territory, where air quality standards for nitrogen oxides and/or photochemical oxidants have not been attained. These amendments also require the installation and/or modification of continuous emission monitoring systems, and require all existing generating units to obtain operating permits. Through the end of 1994, the Company has expended a total of approximately $14.7 million to comply with these nitrogen oxides controls and emission monitoring systems requirements, and it expects to spend approximately $2.0 million during 1995 for this purpose. On September 27, 1994, the Ozone Transport Commission (consisting of the twelve northeastern-most states plus the District of Columbia) adopted a Memorandum of Understanding (MOU) which obligates certain of those states, including Connecticut, to adopt regulations which will further limit emissions from large stationary sources of nitrogen oxides, including utility boilers. The MOU calls for such reductions to occur in two steps; the first in 1999 and the second in 2003. It is expected that such regulations, when promulgated, would become part of the federally mandated revisions to Connecticut's plan for achieving compliance with air quality standards for photochemical oxidants. However, these revisions have not yet been promulgated, and the Company is not yet able to assess accurately the applicability and impact of implementing regulations to and on its generating facilities. Compliance may require substantial additional capital and operational expenditures in the future. In addition, due to the 1990 amendments and other provisions of the Clean Air Act, future construction or modification of fossil-fired generating units and all other sources of air pollution in southwestern Connecticut will be conditioned on installing state-of-the-art nitrogen oxides controls and obtaining nitrogen oxide emission offsets -- in the form of reductions in emissions from other sources -- which may hinder or preclude such construction or modification programs in UI's service area, depending on ambient pollutant levels over which the Company has no control.

The Company's generating stations in Bridgeport and New Haven comply with the air quality and emission performance standards adopted by those cities.

Under the federal Toxic Substances Control Act (TSCA), the EPA has issued regulations that control the use and disposal of polychlorinated biphenyls (PCBs). PCBs had been widely used as insulating fluids in many electric utility transformers and capacitors manufactured before TSCA prohibited any further manufacture of such PCB equipment. Fluids with a concentration of PCBs higher than 500 parts per million and materials (such as electrical capacitors) that contain such fluids must be disposed of through burning in high temperature incinerators approved by the EPA. Solid wastes containing PCBs must be disposed of in either secure chemical waste landfills or in high-efficiency incinerators. In response to EPA regulations, UI has phased out the use of certain PCB capacitors and has tested all Company-owned transformers located inside customer-owned buildings and replaced all transformers found to have fluids with detectable levels of PCBs (higher than 1 part per million) with transformers that have no detectable PCBs. Presently, no transformers having fluids with levels of PCBs higher than 500 parts per million are known by UI to remain in service in its system, except at one of UI's generating stations. Compliance with TSCA regulations has necessitated substantial capital and operational expenditures by UI, and such expenditures may continue to be required in the future, although their magnitude cannot now be estimated. The Company has agreed to participate financially in the remediation of a source of PCB contamination attributed to UI-owned electrical equipment on property in New Haven. Although the scope of the remediation and the extent of UI's participation have not yet been fully determined, the owner of the property has estimated the total remediation cost to be approximately $346,000.

Under the federal Resource Conservation and Recovery Act (RCRA), the generation, transportation, treatment, storage and disposal of hazardous wastes are subject to regulations adopted by the EPA. Connecticut has adopted state regulations that parallel RCRA regulations but are more stringent in some respects. The Company has complied with the notification and application requirements of present regulations, and the procedures by which UI handles, stores, treats and disposes of hazardous waste products have been revised, where necessary, to comply with these regulations.

The Company has estimated that the cost of environmental remediation of its decommissioned Steel Point Station property in Bridgeport will be approximately $11.3 million, and that the value of the property following remediation will not exceed $6 million. In its December 16, 1992 decision on UI's application for retail rate increases, the DPUC provided for additional revenues to be recovered from customers in the amount of $4.3 million of the difference during the period 1993-1996, 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.

RCRA also regulates underground tanks storing petroleum products or hazardous substances, and Connecticut has adopted state regulations governing underground tanks storing petroleum and petroleum products that, in some respects, are more stringent than the federal requirements. The Company has 18 underground storage tanks, which are used primarily for gasoline and fuel oil, that are subject to these regulations. The Company has a testing program to detect leakage from any of its tanks, and it may incur substantial costs for future actions taken to prevent tanks from leaking, to remedy any contamination of groundwater, and to remove and replace older tanks in compliance with federal and state regulations.

In the past, the Company has disposed of residues from operations at landfills, as most other industries have done. In recent years it has been determined that such disposal practices, under certain circumstances, can cause groundwater contamination. Although the Company has no knowledge of the existence of any such contamination, if the Company or regulatory agencies determine that remedial actions must be taken in relation to past disposal practices, the Company may experience substantial costs.

A Connecticut statute authorizes the creation of a lien against all real estate owned by a person causing a discharge of hazardous waste, in favor of the DEP, for the costs incurred by the DEP to contain and remove or mitigate the effects of the discharge. Another Connecticut law requires a person intending to transfer ownership of an establishment that generates more than 100 kilograms per month of hazardous waste to provide the purchaser and the DEP with a declaration that no release of hazardous waste has occurred on the site, or that any wastes on the site are under control, or that the waste will be cleaned up in accordance with a schedule approved by the DEP. Failure to comply with this law entitles the transferee to recover damages from the transferor and renders the transferor strictly liable for the cleanup costs. In addition, the DEP can levy a civil penalty of up to $100,000 for providing false information. UI does not believe that any material claims against the Company will arise under these Connecticut laws.

A Connecticut statute prohibits the commencement of construction or reconstruction of electric generation or transmission facilities without a certificate of environmental compatibility and public need from the Connecticut Siting Council (CSC). In certification proceedings, the CSC holds public hearings, evaluates the basis of the public need for the facility, assesses its probable environmental impact and may impose specific conditions for protection of the environment in any certificate issued. During 1993, a citizens' group appealed to the Connecticut Superior Court from a decision of the CSC declining to reopen the 1991 certification of a transmission line that has since been completed by the Company and The Connecticut Light and Power Company in Fairfield County. The Superior Court dismissed this appeal; but the citizens' group has taken an appeal from the Superior Court's decision, and the Company is unable to predict what impact, if any, the group's actions will have on the operation of the transmission facility.

In complying with existing environmental statutes and regulations and further developments in these and other 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 Company believes any additional costs are recoverable through the ratemaking process. The total amount of these expenditures is not now determinable. See also Item 2. Properties - "Nuclear Generation".

EMPLOYEES

As of December 31, 1994, the Company had 1,377 employees, including 25 in subsidiary operations. Of these, approximately 63% had been with the Company for 10 or more years.

Approximately 722 of the Company's operating, maintenance and clerical employees are represented by Local 470-1, Utility Workers Union of America, AFL-CIO, for collective bargaining purposes. On May 21, 1992, the Company and the union agreed on a three-year contract, effective May 16, 1992. There has been no work stoppage due to labor disagreements since 1966, other than a strike of three days duration in May 1985; and employee relations are considered satisfactory by the Company.

GENERATING FACILITIES

The electric generating capability of the Company as of December 31, 1994, based on summer ratings of the generating units, was as follows:

UI Operated:	Fuel	Year of Installation	Max Claimed Capability, Mw	UI Entitlement %	UI Entitlement Mw
Bridgeport Harbor Station 1	#6 Oil	1957	82.00	100.00	82.00(1)
Bridgeport Harbor Station 2	#6 Oil	1961	170.00	100.00	170.00
Bridgeport Harbor Station 3	#6 Oil/Coal	1968/1985	385.00	100.00	385.00(2)
Bridgeport Harbor Station 4	Jet Oil	1967	17.10	100.00	17.10
New Haven Harbor Station	#6 Oil/Gas	1975	447.00	93.71	418.86(3)
English Station 7	#6 Oil	1948	34.06	100.00	34.06(4)
English Station 8	#6 Oil	1953	38.49	100.00	38.49(4)
Operated by Other Utilities:					
Connecticut Yankee Unit, Haddam, Connecticut	Nuclear	1968	560.10	9.50	53.21(5)
Millstone Unit 3, Waterford, Connecticut	Nuclear	1986	1136.73	3.69	41.89(6)
Seabrook Unit 1, Seabrook, New Hampshire	Nuclear	1990	1150.00	17.50	201.25(7)
Power Purchases From Cogeneration Facilities:					
Bridgeport RESCO, Bridgeport, Connecticut	Refuse	1988	59.45	100.00	59.45
Total					1501.31

(1) Effective January 1, 1994, Bridgeport Harbor Station 1 was removed from operation and dispatching under NEPOOL and was placed in deactivated reserve. See Item 1. Business - "Arrangements with Other Utilities."
(2) The unit has been burning coal since early January 1985.
(3) UI's 93.705% ownership share of total net capability, including 25 MW sold to another utility for a 10-year period, commencing October 1, 1986 and 25 MW involved in a capacity exchange with another utility for a 6.5 year period, commencing May 1, 1993. This unit is jointly owned by UI (93.705%), Fitchburg Gas and Electric Light Company (4.5%) and the electric departments of three Massachusetts municipalities (1.795%). See Item 1. Business - "Fuel Supply".
(4) English Station Units 7 and 8 were placed in deactivated reserve, effective January 1, 1992.
(5) Represents UI's 9.5% entitlement in the unit. See Item 1. Business - "Financing".
(6) Represents UI's 3.685% ownership share of total net capability.
(7) Represents UI's 17.5% ownership share of total net capability. In August 1990, UI sold to and leased back from an owner trust established for the benefit of an institutional investor a portion of UI's 17.5% ownership interest in this unit. This portion of the unit is subject to the lien of a first mortgage granted by the owner trustee.

TABULATION OF PEAK LOADS, RESOURCES, AND MARGINS
1994 ACTUAL, 1995 - 1999 FORECAST
(MEGAWATTS)

	Actual	Forecast				
	1994	1995	1996	1997	1998	1999
At Time of Peak Load on UI's System:						
Capacity of generating units operated by UI (1)	990.96	990.96	990.96	990.96	990.96	990.96
Entitlements in nuclear units (1) (2)						
Connecticut Yankee Unit	53.21	53.21	53.21	53.21	53.21	53.21
Millstone Unit 3	41.89	41.89	41.89	41.89	41.89	41.89
Seabrook Unit 1	201.25	201.25	201.25	201.25	201.25	201.25
	296.35	296.35	296.35	296.35	296.35	296.35
Equivalent capacity value of entitlement in Hydro-Quebec (1) (2)	98.10	98.10	98.10	98.10	98.10	98.10
Purchases from cogeneration facilities						
Bridgeport RESCO	62.00	59.45	59.45	59.45	59.45	59.45
Shelton Landfill (3)			1.88	1.74	1.61	1.50
Purchase from New York Power Authority	1.18	1.32	1.32	1.32	1.32	1.32
Purchases from (sales to) other utilities						
Net power contracts - fossil	15.00	(14.00)	(1.80)	8.20	38.20	38.20
Total generating resources	1463.59	1432.18	1446.26	1456.12	1485.99	1485.88
Calculation of NEPOOL capability responsibility (4)						
Peak load	1131.00	1126.00	1133.00	1135.00	1140.00	1146.00
Required reserve margin	172.50	197.46	225.39	234.92	232.64	237.43
Total capability responsibility	1303.50	1323.46	1358.39	1369.92	1372.64	1383.43
Available Margin (5)	160.09	108.72	87.87	86.20	113.35	102.45

(1) Capacity shown reflects summer ratings of generating units.

(2) Winter ratings of UI nuclear and Hydro-Quebec interconnection's equivalent capacity value entitlements (megawatts):

Connecticut Yankee Unit	-	56.05
Millstone Unit 3	-	42.33
Seabrook Unit 1	-	201.25
Hydro-Quebec	-	66.22

(3) Projected to begin commercial operation by September 1995.

(4) UI's required capacity as a NEPOOL participant.

(5) Total generating resources less capability responsibility. In addition, UI maintains three units (Bridgeport Harbor Station 1 and English Station 7 and 8) in deactivated reserve, representing a total of 154 MW of generating capacity.

During 1994, the peak load on the Company's system was approximately 1,131 megawatts, which occurred in July. UI's total generating capability at the time was 1,462 megawatts, including a 98 megawatt increase in capability provided by the equivalent capacity value of UI's entitlements in the Hydro-Quebec facility and reflecting the net effect of temporary arrangements with other electric utilities and cogenerators. The Company is currently forecasting a compound growth in peak load of 0.5% during the period 1994 to 2004. Based on current forecasts of loads, UI's generating capability will exceed its projected capability responsibility to NEPOOL for generating capacity through at least 2001, and English Station Units 7 and 8 and Bridgeport Harbor Station Unit 1 can be reactivated if higher than anticipated load growth occurs. If, due to the permanent loss of a generating unit or higher than expected load growth, UI's own generating capability becomes inadequate to meet its capability responsibility to NEPOOL, UI expects to be able to reduce the load on its system by the implementation of additional demand-side management programs, to acquire other demand-side and supply-side resources, and/or to purchase capacity from other utilities as necessary. However, because the generation and transmission systems of the major New England utilities, including UI, are operated as if they were a single system, the ability of UI to meet its load is and will be dependent on the ability of these New England utilities to meet the region's load. At the time of the NEPOOL summer peak in July 1994, these New England utilities had 26,555 megawatts of generating capacity, including 1,500 megawatts of interconnection credit of the Hydro-Quebec facility, available to meet the New England peak load of 20,519 megawatts. See "Nuclear Generation" and Item 1. Business - "Competition" and "Arrangements with Other Utilities".

Shown below is a summary of the Company's sources and uses of electricity for 1994.

Sources	Megawatthours (000's)	Uses	
Owned		Retail Customers	5,363
Nuclear (Millstone Unit 3 and Seabrook Unit 1)	1,433		
Coal	2,156	Wholesale	
Oil	1,310	Delivered to NEPOOL	907
Gas & Gas Turbines	48	Contracts	728
Total Owned	4,947		
		Company Use & Losses	289
Purchased			
Nuclear (Connecticut Yankee Unit)	361	Total Uses	7,287
Contracts	922		
NEPOOL	706		
Hydro-Quebec	351		
Total Sources	7,287		

TRANSMISSION AND DISTRIBUTION PLANT

The transmission lines of the Company consist of approximately 100 circuit miles of overhead lines and approximately 19 circuit miles of underground lines, all operated at 345 KV or 115 KV and located within or immediately adjacent to the territory served by the Company. These transmission lines interconnect the Company's English, Bridgeport Harbor and New Haven Harbor generating stations and are part of the New England transmission grid through connections with the transmission lines of The Connecticut Light and Power Company. A major portion of the Company's transmission lines is constructed on a railroad right-of-way pursuant to a Transmission Line Agreement that expires in May 2000.

The Company owns and operates 24 bulk electric supply substations with a capacity of 2,637,000 KVA and 49 distribution substations with a capacity of 282,000 KVA. The Company has 3,123 pole-line miles of overhead distribution lines and 132 conduit-bank miles of underground distribution lines.

See "Capital Expenditure Program" concerning the estimated cost of additions to the Company's transmission and distribution facilities.

CAPITAL EXPENDITURE PROGRAM

The Company's 1995-1999 capital expenditure program, excluding allowance for funds used during construction (AFUDC) and its effect on certain capital related items, is presently budgeted as follows:

	1995	1996	1997 (000's)	1998	1999	Total
Production	$16,848	$26,446	$10,912	$3,424	$34,906	$92,536
Distribution	18,864	16,728	16,884	16,080	16,560	85,116
Transmission	7,500	4,596	8,412	15,060	17,496	53,064
Conservation and Load Management	11,580	9,756	9,468	9,048	9,012	48,864
Nuclear Fuel	8,052	11,280	1,248	11,820	10,128	42,528
Other	12,996	7,370	4,892	5,336	4,778	35,372
Total Expenditures	$75,840	$76,176	$51,816	$60,768	$92,880	$357,480
AFUDC (Pre-tax)	$3,174	$2,437	$2,031	$2,034	$938	
Book Depreciation (1)	59,866	64,195	66,168	69,047	73,301	
Decommissioning	1,823	1,910	2,001	2,097	2,198	
Normalized Tax Depreciation	34,767	36,898	38,382	39,732	42,877	
Accelerated Tax Depreciation	68,743	58,191	59,253	58,655	61,038	
Amortization of Deferred Return on Seabrook Unit 1 Phase-In (2)	12,586	12,586	12,586	12,586	12,586	
Estimated Rate Base (end of period)	$1,209,500	$1,238,035	$1,212,275	$1,184,307	$1,220,861	

(1) Steel Point Station environmental remediation costs of $1,075,000 per year are included each year through 1996.

(2) Deferred return will be amortized over the period 1995-1999.

NUCLEAR GENERATION

General

UI holds ownership and leasehold interests in Seabrook Unit 1 (17.5%) and Millstone Unit 3 (3.685%). UI also owns 9.5% of the common stock of Connecticut Yankee and is entitled to 9.5% of the generating capability of its nuclear generating unit. Each of these nuclear generating units is subject to the licensing requirements and jurisdiction of the NRC under the Atomic Energy Act of 1954, as amended, and to a variety of other state and federal requirements.

The NRC regularly conducts generic reviews of numerous technical issues, ranging from seismic design to education and fitness for duty requirements for licensed plant operators. The outcome of reviews that are currently pending, and the ways in which the nuclear generating units in which UI has interests may be affected by these reviews, cannot be determined; and the cost of complying with any new requirements that might result from the reviews cannot be estimated. However, such costs could be substantial.

Additional capital expenditures and increased operating costs for the nuclear generating units in which UI has interests may result from modifications of these facilities or their operating procedures required by the NRC, or from actions taken by other joint owners or companies having entitlements in the units. Some equipment modifications have required and may in the future require shutdowns or deratings of the generating units that would not otherwise be necessary and that result in additional costs for replacement power. The amounts of additional capital expenditures, increased operating costs and replacement power costs cannot now be predicted, but they have been and may in the future be substantial.

Public controversy concerning nuclear power could also adversely affect the nuclear generating units in which UI has interests. Proposals to force the premature shutdown of nuclear plants in other New England states have received serious attention, and the licensing of Seabrook Unit 1 was a regional issue. The continuing controversy can be expected to increase the costs of operating the nuclear generating units in which UI has interests; and it is possible that one or more of the units could be shut down prematurely.

Insurance Requirements

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 $75.5 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 $75.5 million, or $3.775 million. The maximum assessment is adjusted at least every five years to reflect the impact of inflation. Based on its interests in nuclear generating units, the Company estimates its maximum liability would be $23.2 million per incident. However, assessment would be limited to $3.1 million per incident, per year. With respect to each of the operating 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.

The NRC requires nuclear generating units 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 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.

Waste Disposal and 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, beginning in 1998, 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 is to take title to and dispose of the utilities' high level wastes and spent nuclear fuel beginning no later than 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010, 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.

Until the federal govern[illegible] [illegible]gins receiving such materials in accordance with the Nuclear Waste Policy Act, operating nuclear generati[illegible] [illegible]its will need to retain high level wastes and spent fuel on-site or make other provisions for their storage. Storage facilities for Millstone Unit 3 are expected to be adequate for the projected life of the unit. Storage facilities for the Connecticut Yankee unit are expected to be adequate through the mid-1990s. Storage facilities for Seabrook Unit 1 are expected to be adequate until at least 2010. Fuel consolidation and compaction technologies are being developed and are expected to provide adequate storage capability for the projected lives of the latter two units. In addition, other licensed technologies, such as dry storage casks, can accommodate spent fuel storage requirements.

Disposal costs for low-level radioactive wastes (LLW) that result from normal operation of nuclear generating units have increased significantly in recent years and are expected to continue to rise. The cost increases are functions of increased packaging and transportation costs and higher fees and surcharges charged by the disposal facilities. As of June 30, 1994, the disposal facility in Barnwell, South Carolina was closed to all LLW disposal for New England nuclear units, forcing all of these units into on-site storage of LLW produced.

Pursuant to the Low-Level Radioactive Waste Policy Act of 1980, each state is responsible for providing disposal facilities for LLW generated within the state and is authorized to join with other states into regional compacts to jointly fulfill their responsibilities. The Connecticut Hazardous Waste Management Service (the Service), a state quasi-public corporation, was charged with coordinating the establishment of a facility for disposal of LLW originating in Connecticut. In June 1991, the Service announced that it had selected three potential sites in north-central Connecticut for further study. The Service's announcement provoked intense controversy in the affected municipalities and resulted in legislative action to stop the selection process. On February 1, 1993, the Service presented to the legislature a new site selection plan under which communities are urged to volunteer a site for a facility in return for financial and other incentives. The volunteer process is being continued through 1996. The Service's activities in this regard are funded by assessments on Connecticut's LLW generators. Due to a change in the volunteer process, there was no assessment for the 1994-1995 fiscal year and the state projects no assessment for the 1995-1996 and 1996-1997 fiscal years. The service currently projects that a disposal site will be designated by 2002, although there are admitted inherent uncertainties in this projection.

Additional LLW storage capacity has been or can be constructed or acquired at the Millstone and Connecticut Yankee sites to provide for temporary storage of LLW should that become necessary. Connecticut LLW can be managed by volume reduction, storage or shipment at least through 2000. The Company cannot predict whether and when a 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 Seabrook Unit 1 has been denied access to existing disposal facilities. Therefore, LLW generated by Seabrook Unit 1 is being stored on-site. The Seabrook storage facility currently has capacity to store at least five years' accumulation of waste generated by Seabrook, and the plant operator plans to expand its storage capacity as necessary.

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 to cover expected decommissioning costs. Changes in NRC requirements or technology can increase estimated decommissioning costs, and UI's customers in future years may experience higher electric rates to offset the effects of any insufficient rate recovery in prior years.

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 $376 million (in 1995 dollars) as the decommissioning cost estimate for Seabrook Unit 1. This estimate premises the prompt removal and dismantling of the Unit at the end of its estimated 40-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 1994 was $1.3 million. UI's share of the fund at December 31, 1994 was approximately $5.2 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. Current decommissioning cost estimates for Millstone Unit 3 and the Connecticut Yankee Unit are $448 million (in 1995 dollars) and $357 million (in 1995 dollars), respectively. These estimates premise the prompt removal and dismantling of each unit at the end of its estimated 36-year energy producing life. Monthly decommissioning payments, based on these cost estimates, are being made to decommissioning trust funds managed by Northeast Utilities. UI's share of the Millstone Unit 3 decommissioning payments made during 1994 was $388,000. UI's share of the fund at December 31, 1994 was approximately $2.4 million. For the Company's 9.5% equity ownership in Connecticut Yankee, decommissioning costs of $1.3 million were funded by UI during 1994, and UI's share of the fund at December 31, 1994 was $14.1 million.

Item 3. Legal Proceedings.

On November 2, 1993, the Company received "updated" personal property tax bills from the City of New Haven (the City) for the tax year 1991-1992, aggregating $6.6 million, based on an audit by the City's tax assessor. On May 7, 1994, the Company received a "Certificate of Correction....to correct a clerical omission or mistake" from the City's tax assessor relative to the assessed value of the Company's personal property for the tax year 1994-1995, which certificate purports to increase said assessed value by approximately 53% above the tax assessor's valuation at February 28, 1994. The Company is contesting each of these actions of the City's tax assessor vigorously, and has commenced actions in the Superior Court to enjoin the City from any effort to collect the "updated" personal property tax bills for the tax year 1991-1992 and challenging both the May 7, 1994 "Certificate of Correction" and the tax assessor's valuation at February 28, 1994. In December of 1994, the City's tax assessor conducted hearings regarding the assessed value of the Company's personal property for the tax years 1992-1993 and 1993-1994; and the Company anticipates that the City will take some action to revalue the Company's personal property for those tax years. On March 1, 1995, the Company received from the City notices of assessment changes, increasing the assessed valuation of the Company's personal property for the tax year 1995-1996 by 48% over the valuation declared by the Company. The Company expects to take the legal actions necessary to challenge these increases. It is the present opinion of the Company that the ultimate outcome of this dispute will not have a significant impact on the financial position of the Company.

On December 30, 1994, the Company settled its property tax dispute with the City of Bridgeport. See "Notes to Consolidated Financial Statements - Note (N)".

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the fourth quarter of the fiscal year ended December 31, 1994.

EXECUTIVE OFFICERS OF THE COMPANY

The names and ages of all executive officers of the Company and all such persons chosen to become executive officers, all positions and offices with the Company held by each such person, and the period during which he or she has served as an officer in the office indicated, are as follows:

Name	Age	Position	Effective Date
Richard J. Grossi	59	Chairman of the Board of Directors and Chief Executive Officer	May 1, 1991
Robert L. Fiscus	57	President and Chief Financial Officer	May 1, 1991
James F. Crowe	52	Executive Vice President and Chief Customer Officer	January 1, 1994
Rita L. Bowlby	56	Vice President-Corporate Affairs	February 1, 1993
Raymond G. Dube	52	Vice President-Transmission and Distribution	October 1, 1994
Stephen F. Goldschmidt	49	Vice President-Information Resources	January 1, 1994
Albert N. Henricksen	53	Vice President-Administration	January 1, 1994
David W. Hoskinson	59	Vice President-Generation	January 1, 1994
Robert H. Hyde	54	Vice President-Customer Services	January 1, 1986
E. Jon Majkowski	52	Vice President	May 1, 1992
Anthony J. Vallillo	46	Vice President-Marketing	June 1, 1992
James L. Benjamin	53	Controller	January 1, 1981
Kurt D. Mohlman	46	Treasurer and Secretary	January 1, 1994
Charles J. Pepe	46	Assistant Treasurer and Assistant Secretary	January 1, 1994

There is no family relationship between any director, executive officer, or person nominated or chosen to become a director or executive officer of the Company. All executive officers of the Company hold office during the pleasure of the Company's Board of Directors and Messrs. Grossi, Fiscus and Crowe have each entered into an employment agreement with the Company. There is no arrangement or understanding between any executive officer of the Company and any other person pursuant to which such officer was selected as an officer.

A brief account of the business experience during the past five years of each executive officer of the Company is as follows:

Richard J. Grossi. Mr. Grossi served as President and Chief Operating Officer during the period January 1, 1990 to May 1, 1991. He has served as Chairman of the Board of Directors and Chief Executive Officer since May 1, 1991.

Robert L. Fiscus. Mr. Fiscus served as Executive Vice President and Chief Financial Officer of the Company during the period January 1, 1990 to May 1, 1991. He has served as President and Chief Financial Officer since May 1, 1991.

James F. Crowe. Mr. Crowe served as Senior Vice President-Marketing of the Company during the period January 1, 1990 to May 1, 1992, and as Executive Vice President from May 1, 1992 to January 1, 1994. He has served as Executive Vice President and Chief Customer Officer since January 1, 1994.

Rita L. Bowlby. Ms. Bowlby has served as Vice President-Corporate Affairs since February 1, 1993. Prior to joining the Company, during the period from January 1, 1990 to February 1, 1993, she served as President of Bowlby & Associates, a business-to-business communications agency in Farmington, Connecticut.

Raymond G. Dube. Mr. Dube served as Transmission Manager during the period January 1, 1990 to July 1, 1992, as Director of Transmission & Distribution Operations from July 1, 1992 to March 1, 1994 and Director of Electric Systems from March 1, 1994 to October 1, 1994. He has served as Vice President-Transmission and Distribution since October 1, 1994.

Stephen F. Goldschmidt. Mr. Goldschmidt served as Vice President-Planning from January 1, 1990 to January 1, 1994. He has served as Vice President-Information Resources since January 1, 1994.

Albert N. Henricksen. Mr. Henricksen served as Vice President-Engineering of the Company during the period January 1, 1990 to July 23, 1990, and as Vice President-Human and Environmental Resources from July 23, 1990 to January 1, 1994. He has served as Vice President-Administration since January 1, 1994.

David W. Hoskinson. Mr. Hoskinson served as Senior Vice President-Operations of the Company during the period January 1, 1990 to July 23, 1990, and as Senior Vice President-Generation Engineering and Operations from July 23, 1990 to January 1, 1994. He has served as Vice President-Generation since January 1, 1994.

Robert H. Hyde. Mr. Hyde has served as Vice President-Customer Services of the Company during the five-year period.

E. Jon Majkowski. Mr. Majkowski served as Vice President-Public Affairs of the Company during the period January 1, 1990 to May 1, 1992. He has served as Vice President since May 1, 1992.

Anthony J. Vallillo. Mr. Vallillo served as Director of Sales and Market Development of the Company during the period January 1, 1990 to December 1, 1990, and as Director of Marketing from December 1, 1990 to June 1, 1992. He has served as Vice President-Marketing since June 1, 1992.

James L. Benjamin. Mr. Benjamin has served as Controller of the Company during the five-year period.

Kurt D. Mohlman. Mr. Mohlman served as Director of Financial Planning during the period January 1, 1990 to September 1, 1990 and as Director of Financial Planning and Investor Relations from September 1, 1990 to January 1, 1994. He has served as Treasurer and Secretary of the Company since January 1, 1994.

Charles J. Pepe. Mr. Pepe served as Director of Financing during the period January 1, 1990 to January 1, 1994. He has served as Assistant Treasurer and Assistant Secretary of the Company since January 1, 1994.

PART II

Item 5. Market for the Company's Common Equity and Related Stockholder Matters.

UI's Common Stock is traded on the New York Stock Exchange, where the high and low sale prices during 1994 and 1993 were as follows:

	1994 Sale Price		1993 Sale Price	
	High	Low	High	Low
First Quarter	39 1/2	35 1/4	43 5/8	41
Second Quarter	37 1/8	32 1/2	44	41 3/4
Third Quarter	34 1/2	29 1/8	45 7/8	42 5/8
Fourth Quarter	30 1/2	29	45 1/4	38 1/2

UI has paid quarterly dividends on its Common Stock since 1900. The quarterly dividends declared in 1993 and 1994 were at a rate of 66 1/2 cents per share and 69 cents per share, respectively.

The indenture under which the Company's 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 $87.2 million were free from such limitations at December 31, 1994.

As of February 28, 1995, there were 17,910 Common Stock shareowners of record.

Item 6. Selected Financial Data

	1994		1993		1992	
Financial Results of Operation ($000's)						
Sales of electricity:						
Retail						
Residential	$252,386		$238,185		$226,455	
Commercial	250,771	(2)	256,559		253,456	(2)
Industrial	104,242	(2)	97,466		97,010	(2)
Other	11,469		11,349		11,065	
Total Retail	618,868		603,559		587,986	
Wholesale (1)	34,927		45,931		75,484	
Other operating revenues	2,953		3,533		3,855	
Total operating revenues	656,748		653,023		667,325	
Fuel and interchange energy -net:						
Retail -own load	99,589		98,694		108,084	
Wholesale	27,765		39,356		55,169	
Capacity purchased-net	44,769		47,424		43,560	
Depreciation	58,165		56,287		50,706	
Other operating expenses, excluding tax expense	194,270		205,207		193,841	
Gross earnings tax	27,403		27,955		27,362	
Other non-income taxes	32,458		29,977		31,869	
Total operating expenses, excluding income taxes	484,419		504,900		510,591	
Deferred return Seabrook Unit 1	0		7,497		15,959	
AFUDC	3,463		4,067		3,232	
Other non-operating income(loss)	(1,907)		71		18,545	
Interest expense:						
Long-term debt	73,772		80,030		88,666	
Other	10,301		12,260		12,882	
Total	84,073		92,290		101,548	
Income tax expense:						
Operating income tax	44,937		33,309		48,712	
Non-operating income tax	(3,214)		(6,322)		(12,558)	
Total	41,723		26,987		36,154	
Income(loss) before cumulative effect of accounting change	48,089		40,481		56,768	
Cumulative effect of change in accounting - net of tax	(1,294)		0		0	
Net income (loss)	46,795		40,481	(3)	56,768	
Preferred and preference stock dividends	3,323		4,318		4,338	
Income (loss) applicable to common stock	$43,472		$36,163		$52,430	
Operating income	$127,392		$114,814		$108,022	
Financial Condition ($000's)						
Plant in service-net	$1,268,145		$1,243,426		$1,224,058	
Construction work in progress	57,669		77,395		59,809	
Plant-related regulatory asset	0		0		0	
Other property and investments	53,267		58,096		65,320	
Current assets	157,309		187,981		247,954	
Regulatory assets	538,601		567,394		556,493	
Total Assets	$2,074,991		$2,134,292		$2,153,634	
Common stock equity	$428,028		$423,324		$422,746	
Preferred and preference stock	44,700		60,945		60,945	
Long-term debt excluding current portion	708,340		875,268		893,457	
Noncurrent liabilities	29,281		29,119		25,853	
Current portion of long-term debt	193,133		143,333		92,833	
Notes payable	67,000		0		84,099	
Other current liabilities	152,261		150,890		133,471	
Regulatory liabilities, principally deferred tax liabilities	452,248		451,413		440,230	
Total Capitalization and Liabilities	$2,074,991		$2,134,292		$2,153,634	

(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.

1991	1990	1989	1988	1987	1986	1985
$226,751	$211,891	$205,183	$200,170	$188,740	$178,268	$190,880
255,782	234,704	219,852	208,801	195,972	180,888	192,658
91,895	94,526	92,855	96,665	100,354	99,939	118,637
10,886	10,536	9,943	9,732	9,480	9,516	10,367
585,314	551,657	527,833	515,368	494,546	468,611	512,542
84,236	85,657	77,925	63,263	54,708	48,010	49,164
3,821	3,332	3,348	3,570	3,077	2,508	2,394
673,371	640,646	609,106	582,201	552,331	519,129	564,100
123,010	119,285	128,739	121,425	131,471	126,778	175,764
61,858	69,117	62,681	53,837	51,411	46,466	49,066
44,668	42,827	50,234	35,465	17,746	15,028	10,112
48,181	36,526	35,618	24,069	37,160	22,112	18,128
189,327	180,592	155,282	143,822	138,315	131,448	122,567
27,223	25,595	24,506	23,948	22,997	21,838	25,221
28,673	24,648	20,294	21,695	17,194	17,991	16,586
522,940	498,590	477,354	424,261	416,294	381,661	417,424
17,970	21,503	0	0	0	0	0
5,190	3,443	65,443	75,656	81,419	78,044	62,623
2,697	22,654	(219,742)	(23,369)	(97,686)	(75,380)	29,838
90,296	94,056	91,126	90,022	88,700	88,610	72,068
9,847	15,468	22,849	12,069	9,228	2,223	5,334
100,143	109,524	113,975	102,091	97,928	90,833	77,402
47,231	43,493	37,963	44,045	50,633	51,419	62,047
(19,299)	(17,409)	(101,135)	(14,548)	(37,440)	(33,884)	(3,317)
27,932	26,084	(63,172)	29,497	13,193	17,535	58,730
48,213	54,048	(73,350)	78,639	8,649	31,764	103,005
7,337	0	0	0	0	0	0
55,550	54,048	(73,350)	78,639	8,649	31,764	103,005
4,530	4,751	8,233	11,348	11,953	18,969	20,339
$51,020	$49,297	($81,583)	$67,291	($3,304)	$12,795	$82,666
$103,200	$98,563	$93,789	$113,895	$85,404	$86,049	$84,629
$1,219,871	$1,209,173	$562,473	$560,930	$563,210	$571,549	$425,873
54,771	50,257	675,831	812,246	737,169	742,585	845,112
0	0	81,768	88,339	68,603	55,497	0
79,009	90,006	91,648	83,860	76,032	70,927	60,127
164,839	161,066	170,823	166,270	122,075	107,399	214,057
554,365	553,986	605,696	653,418	610,913	607,294	93,350
$2,072,855	$2,064,488	$2,188,239	$2,365,063	$2,178,002	$2,155,251	$1,638,519
$401,771	$379,812	$362,584	$473,674	$438,564	$476,108	$493,261
62,640	69,700	70,000	104,000	110,000	133,000	166,000
909,998	899,993	868,884	862,287	767,559	661,548	664,648
96,973	99,933	107,781	111,971	95,070	81,263	59,814
37,500	41,667	18,667	3,667	28,667	18,667	3,667
13,000	15,000	45,000	0	0	25,675	0
127,524	149,090	142,878	122,237	117,009	100,666	131,803
423,449	409,293	572,445	687,227	621,133	658,324	119,326
$2,072,855	$2,064,488	$2,188,239	$2,365,063	$2,178,002	$2,155,251	$1,638,519

(2) Includes reclassification of certain Commercial and Industrial customers.
(3) Includes the effect of a reorganization charge of $7.8 million, after-tax.

Item 6. Selected Financial Data (continued)

	1994		1993		1992	
Common Stock Data						
Average number of shares outstanding	14,085,452		14,063,854		13,941,150	
Number of shares outstanding at year-end	14,086,691		14,083,291		14,033,148	
Earnings(loss) per share (average)	$3.09	(1)	$2.57	(3)	$3.76	
Book value per share	$30.39		$30.06		$30.12	
Average return on equity						
Total	10.19%		8.45%		12.67%	
Utility	12.50%		10.97%		14.46%	
Dividends declared per share	$2.76		$2.66		$2.56	
Market Price:						
High	$39.500		$45.875		$42.000	
Low	$29.000		$38.500		$34.125	
Year-end	$29.500		$40.250		$41.500	
Net cash provided by operating activities, less dividends ($000's)	$94,807		$104,547		$109,020	
Capital expenditures, excluding AFUDC	$63,044		$94,743		$66,390	
Other Financial and Statistical Data						
Sales by class (MWH's)						
Residential	1,892,955		1,844,041		1,799,456	
Commercial	2,285,942	(2)	2,359,023		2,303,216	(2)
Industrial	1,135,831	(2)	1,036,547		997,168	(2)
Other	48,718		50,715		52,984	
Total	5,363,446		5,290,326		5,152,824	
Number of retail customers by class (average)						
Residential	275,441		273,752		273,936	
Commercial	28,394	(2)	28,968		28,848	(2)
Industrial	1,538	(2)	959		1,017	(2)
Other	1,127		1,175		1,358	
Total	306,500		304,854		305,159	
Revenue per kilowatt hour by class (cents)						
Residential	13.33		12.92		12.58	
Commercial	10.97		10.88		11.00	
Industrial	9.18		9.40		9.73	
Average large industrial customers time of use rate (cents)	8.69		8.89		8.84	
System requirements (MWH)	5,652,657		5,630,581		5,475,664	
Peak load - kilowatts	1,130,780		1,114,900		1,034,440	
Generating capability- peak(kilowatts)	1,462,290		1,515,420		1,402,800	
Load factor	57.07%		57.65%		60.26%	
Fuel generation mix percentages						
Coal	35		31		34	
Oil	14		16		17	
Nuclear	32		38		35	
Cogeneration	9		8		8	
Gas	4		1		1	
Hydro	6		6		5	
Revenues - retail sales ($000's)						
Base	$619,097		$605,887		$608,176	
Fuel Adjustment Clause	(229)		(2,328)		(41,221)	
Sales Provision Adjustment	0		0		21,031	
Total	$618,868		$603,559		$587,986	
Revenue - retail sales per KWH (cents)						
Base	11.54		11.45		11.80	
Fuel Adjustment Clause	0.00		(0.04)		(0.80)	
Sales Provision Adjustment	0.00		0.00		0.41	
Total	11.54		11.41		11.41	
Fuel and energy cost per KWH (cents)	1.76		1.75		2.43	
Fossil	2.14		2.08		2.98	
Nuclear	0.94		1.23		1.42	
Number of employees	1,377		1,490		1,554	
Total payroll($000 'S)	$75,441		$75,305		$74,052	

(1) Includes the cumulative effect of accounting change for postemployment benefits, which decreased earnings by $0.09 per share.

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

1991	1990	1989	1988	1987	1986	1985
13,899,906	13,887,748	13,887,748	13,887,748	13,887,654	13,827,431	13,623,093
13,932,348	13,887,748	13,887,748	13,887,748	13,887,748	13,886,566	13,720,050
$3.67 (4)	$3.55	($5.87)	$4.85	($0.24)	$0.93	$6.07
$28.84	$27.35	$26.11	$34.11	$31.58	$34.29	$35.95
13.01%	13.39%	-18.88%	14.75%	-0.72%	2.64%	17.83%
13.39%	13.97%	20.21%	32.91%	15.34%	16.81%	16.21%
$2.44	$2.32	$2.32	$2.32	$2.32	$2.32	$2.08
$39.125	$34.125	$34.250	$27.500	$34.000	$36.250	$27.125
$30.000	$26.875	$24.750	$19.125	$21.250	$26.625	$13.750
$39.000	$31.125	$34.250	$26.875	$26.875	$29.250	$27.000
$73,865	$39,189	$31,437	$40,607	$37,986	$16,796	$47,239
$63,157	$64,018	$77,041	$83,735	$73,253	$116,124	$116,480
1,851,447	1,826,700	1,883,363	1,870,318	1,780,333	1,700,302	1,654,591
2,347,757	2,259,340	2,254,099	2,174,200	2,046,289	1,914,889	1,810,192
980,071	1,060,751	1,109,119	1,186,336	1,236,151	1,232,209	1,286,402
55,118	58,013	60,427	61,303	62,246	65,533	68,064
5,234,393	5,204,804	5,307,008	5,292,157	5,125,019	4,912,933	4,819,249
274,064	275,637	276,385	274,884	271,302	267,509	264,112
29,768	29,808	29,526	28,826	28,103	27,215	26,679
268	319	347	367	369	372	386
1,361	1,352	1,316	1,267	1,191	1,179	1,145
305,461	307,116	307,574	305,344	300,965	296,275	292,322
12.25	11.60	10.89	10.70	10.60	10.48	11.54
10.89	10.39	9.75	9.60	9.58	9.45	10.64
9.38	8.91	8.37	8.15	8.12	8.11	9.22
8.64	8.06	7.58	7.14	7.04	6.79	n/a
5,541,477	5,501,495	5,603,502	5,581,897	5,403,519	5,182,516	5,058,084
1,145,820	1,054,600	1,094,400	1,132,100	1,039,600	985,710	1,019,980
1,474,190	1,449,600	1,289,800	1,271,500	1,236,000	1,309,700	1,169,700
55.21%	59.55%	58.45%	56.13%	59.33%	60.02%	56.61%
34	43	39	37	42	37	40
21	24	37	41	37	53	51
29	20	11	11	10	9	9
9	9	9	7	1	0	0
4	3	3	0	5	0	0
3	1		4	5	1	0
$607,997	$589,346	$577,611	$574,422	$558,060	$537,147	$532,264
(37,497)	(45,900)	(49,778)	(59,054)	(63,514)	(68,536)	(19,722)
14,814	8,211	0	0	0	0	0
$585,314	$551,657	$527,833	$515,368	$494,546	$468,611	$512,542
11.62	11.32	10.88	10.85	10.89	10.93	11.04
(0.72)	(0.88)	(0.93)	(1.11)	(1.24)	(1.39)	(0.40)
0.28	0.16	0.00	0.00	0.00	0.00	0.00
11.18	10.60	9.95	9.74	9.65	9.54	10.64
2.67	2.63	2.78	2.53	2.54	2.45	3.48
3.11	2.89	2.98	2.74	2.58	2.58	3.71
1.62	1.55	0.89	0.87	0.94	1.02	1.01
1,571	1,587	1,627	1,620	1,604	1,576	1,501
$71,888	$69,237	$65,175	$62,387	$57,207	$52,782	$49,150

(3) Includes the effect of a reorganization charge which decreased earnings by $.56 per share.

(4) Includes the cumulative effect of accounting change for municipal property taxes, which increased earnings by $0.53 per share.

MAJOR INFLUENCES ON FINANCIAL CONDITION

The Company's financial condition will continue to be dependent on the level of retail and wholesale sales. The two primary factors that affect sales volume are economic conditions and weather. A 1% increase in retail sales would increase revenues by $6.0 million (sales margin by about $5.0 million). However, a return to normal weather could decrease revenues by $4.5 million (sales margin by $3.4 million).

Another major factor affecting the Company's financial condition will be the Company's ability to control expenses. A significant reduction in interest expense has been achieved since 1989, and additional savings of $4-$5 million are expected in 1995 due to debt reduction and refinancing. Since 1990, annual growth in total operation and maintenance expense, excluding one-time items and cogeneration capacity purchases, has averaged approximately 2.0%, and the Company hopes to restrict future increases to less than the rate of inflation.

LIQUIDITY AND CAPITAL RESOURCES

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

	1995	1996	1997 (000's)	1998	1999
Capital Expenditure Program	$ 75,840	$76,176	$ 51,816	$ 60,768	$ 92,880
Long-term Debt Maturities	97,000	-	50,000	100,000	100,000
Mandatory Redemptions/Repayments	66,133	12,770	15,171	15,562	15,988
Total Capital Requirements	$238,973	$88,946	$116,987	$176,330	$208,868

The Company presently estimates that its cash on hand and temporary cash investments at the beginning of 1995, totaling $11.4 million, and its projected net cash provided by operations, less dividends, of $105.3 million, will be sufficient to fund the Company's entire capital expenditure program of $75.8 million and $40.9 million of the $163.1 million necessary to satisfy the 1995 requirements for long-term debt maturities and mandatory long-term debt redemptions and repayments. The Company presently estimates that its projected net cash provided by operations, less dividends, of $97.7 million, will be sufficient to fund the Company's entire capital expenditure program of $76.2 million and all of the Company's 1996 requirements for mandatory redemptions and repayments of $12.8 million. The Company presently estimates that its projected net cash provided by operations, less dividends, of $282.0 million, will be sufficient to fund the Company's entire capital expenditure program of $205.5 million and $76.5 million of the $296.7 million necessary to satisfy the 1997 through 1999 requirements for long-term debt maturities and mandatory long-term debt redemptions and repayments.

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 $225 million revolving credit agreement with a group of banks, described below, the Company expects to be able to satisfy its external financing needs by issuing common stock, preferred stock and additional short-term and long-term debt, although the continued availability of these methods of financing will be dependent on many factors, including conditions in the securities markets, economic conditions, and the level of the Company's income and cash flow.

On August 18, 1994, United Capital Funding Partnership L.P. ("United Capital"), a special purpose limited partnership in which the Company owns all of the general partner interests, was formed for the sole purpose of issuing its limited partner interests, represented by Preferred Capital Securities ("Capital Securities"), and lending the proceeds thereof to the Company in return for Junior Subordinated Deferrable Interest Debentures ("Subordinated Debentures"). United Capital and the Company have registered $100 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. The Company has also registered $200 million principal amount of Notes for sale to the public from time to time, in one or more series, under the Securities Act of 1933.

At December 31, 1994, the Company had $11.4 million of cash and temporary cash investments, a decrease of $36.8 million from the balance at December 31, 1993. The components of this decrease, which are detailed in the Consolidated Statement of Cash Flows, are summarized as follows:

	(Millions)
Balance, December 31, 1993	$ 48.2
Net cash provided by operating activities	137.0
Net cash provided by (used in) financing activities:	
- Financing activities, excluding dividend payments	(68.5)
- Dividend payments	(42.2)
Cash invested in plant, including nuclear fuel	(63.1)
Net decrease	(36.8)
Balance, December 31, 1994	$ 11.4

The Company has a revolving credit agreement with a group of banks, which currently extends to December 14, 1995. The borrowing limit of this facility is $225 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, 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, 1994, the Company had $67 million in short-term borrowings outstanding under this facility.

In January 1995, the Company entered into interest rate cap agreements, with several banks, to protect $100 million of its short-term debt from increases in short-term interest rates. The agreements provide that if the LIBOR (London Interbank Offering Rate), for one-month borrowings, exceeds 8.50% on the 17th of any month during the period beginning February 17, 1995 and ending January 17, 1997, the banks will pay to the Company the difference between that LIBOR and 8.50%, multiplied by $100 million, for the subsequent one-month period.

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, 1994, this coverage ratio was 2.86.

The Company has a Fossil Fuel Supply Agreement with a financial institution providing for financing up to $37.5 million in fossil fuel purchases. Under this agreement, the financing entity acquires and stores natural gas, coal and fuel oil for sale to the Company, and the Company purchases 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 1996. At December 31, 1994, approximately $10.7 million of fossil fuel purchases were being financed under this agreement.

UI has three wholly-owned subsidiaries. Research Center, Inc. (RCI) has been formed to participate in the development of one or more regulated power production ventures, including possible participation in arrangements for the future development of independent power production and cogeneration facilities. United Energy International, Inc. (UEI) was formed to facilitate participation in a joint venture relating to power production plants abroad. United Resources, Inc. (URI) serves as the parent corporation for several unregulated businesses, each of which is incorporated separately to participate in business ventures that will complement and enhance UI's electric utility business and serve the interests of the Company and its shareholders and customers.

Four wholly-owned subsidiaries of URI have been incorporated. Souwestcon Properties, Inc. (SPI) participated as a 25% partner in the ownership of a medical hotel building in New Haven, which has recently been sold. SPI no longer owns any property and is currently inactive. A second wholly-owned subsidiary of URI is Thermal Energies, Inc., which 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 37% 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 and industrial facilities. A fourth URI subsidiary, American Payment Systems, Inc., manages agents and equipment for electronic data processing of bill payments made by customers of utilities, including UI, at neighborhood businesses. In addition to these subsidiaries, URI also has a 90% ownership interest in Ventana Corporation, which offers energy conservation engineering and project management services to governmental and private institutions.

The Board of Directors of the Company has authorized the investment of a maximum of $18.0 million, in the aggregate, of the Company's assets in all of URI's ventures, UEI and RCI, and, at December 31, 1994, approximately $14.5 million had been so invested.

RESULTS OF OPERATIONS

1994 vs. 1993

Earnings for the year 1994 were $43.5 million, or $3.09 per share, up $7.3 million, or $.52 per share, from 1993. This increase reflects $7.8 million (after-tax), or $.56 per share, from the absence of a one-time charge taken in the fourth quarter of 1993 for the estimated costs of a reorganization and early retirement program associated with the Company's organization review and cost reduction program. Earnings decreased $1.5 million (after-tax), or $.10 per share, due to a one-time charge resulting from the settlement of a dispute with the City of Bridgeport regarding past taxes payable by the Company on its personal property in that city. Earnings also decreased $1.3 million (after-tax), or $.09 per share, from an accounting change made in the first quarter of 1994 to implement Statement of Financial Accounting Standards No. 112. Earnings per share for 1994, excluding one-time items and accounting changes, increased by $.15 per share, to $3.28 per share, from $3.13 per share for 1993.

Retail operating revenues increased about $15.3 million for the year 1994 over the year 1993: $12.5 million from retail rate changes, $7.1 million from higher retail kilowatt-hour sales and $1.2 million to recover higher "pass-through"expenses, partly offset by $5.4 million from an increase in non-cash revenue amortization.

The $12.5 million retail revenue increase due to rate changes resulted from a rate increase granted by the DPUC in 1992 effective January 1, 1994. Included in this $12.5 million was $5.4 million to collect sales adjustment revenues booked in prior periods. A separate non-cash amortization charge to revenue was increased by $5.4 million to eliminate any current period revenue effect of these sales adjustment rate changes.

Retail kilowatt-hour sales for the year increased 1.4% over the prior year, producing additional retail revenues of $7.1 million and additional sales margin (revenue less fuel expense and revenue-based taxes) of about [illegible]0 million. There was virtually no retail kilowatt-hour sales change from weather factors between 1994 and 1993. Weather for the year of 1994 was more severe than "normal", augmenting sales by 0.9% and producing revenues of about $4.5 million and sales margin of about $3.4 million. Retail revenues to recover "pass-through" charges for certain expense changes, including fossil fuel, increased by $1.2 million in 1994 over 1993.

Wholesale "capacity" revenues increased by $0.6 million in 1994 from their 1993 level. Wholesale "energy" revenues, as well as the associated fuel expense, decreased by $11.6 million from 1993 to 1994.

Retail fuel and energy expenses increased $0.9 million for the year of 1994 over 1993. A sales margin increase (reduction of expense) of about $1.2 million resulted from nuclear unit operations and nuclear fuel prices. There were other offsetting fuel expense increases of $2.1 million.

Operating expenses for operations, maintenance and purchased capacity charges in 1994 increased by $0.6 million compared to 1993. Purchased capacity was $2.7 million lower than 1993 due to the absence of a scheduled outage at the Connecticut Yankee Unit, compared to ten weeks of scheduled outage in 1993. Operation and maintenance increased $3.3 million. A $5.1 million increase resulted from higher repair costs at Seabrook Unit 1 reflecting nine weeks of scheduled outage and ten weeks of unscheduled outage in 1994. However, other operation and maintenance expenses decreased by a net $1.8 million, reflecting reduced maintenance costs at the Company's fossil fuel generating plants, the impacts of the 1993 reorganization and early retirement program, and re-engineering efforts.

Other operating expenses, excluding one-time items and their tax effects, increased approximately $7.6 million in 1994 from 1993 due to higher depreciation and income taxes.

Other income and (deductions) decreased $13.2 million for the year of 1994 from the prior year, due principally to the elimination of the deferred returns (after-tax and not representing current cash income) related to the portion of the cost of Seabrook Unit 1 that had not been in the Company's rate base in 1993 and the elimination of the income tax benefits associated with the interest costs of carrying that portion of the unit's cost, lower AFUDC from lower construction costs and a lower AFUDC rate, the write-off of certain terminated project costs previously capitalized, and higher losses related to unregulated subsidiaries. The revenue to support the increased rate base in 1994, and the income tax benefits of the associated cost of debt, are reflected in operating revenues and expenses.

Interest costs and preferred stock dividends decreased by $9.2 million in 1994 compared to 1993. Through its refinancing program, the Company has taken advantage of lower interest rates in both 1993 and 1994.

<u>1993 vs. 1992</u>

Earnings for the year 1993 were $36.2 million, or $2.57 per share, down $16.3 million, or $1.19 per share, from 1992. This decrease reflects a one-time reorganization charge of approximately $7.8 million after-tax, or $.56 per share, and the non-recurrence of one-time gains of $.59 per share in 1992. Earnings per share for 1993, excluding one-time items and accounting changes, decreased by $.04 per share, to $3.13 per share from $3.17 per share for 1992.

Sales margin increased by $10.3 million for the year. Retail revenues increased $36.6 million; $20.7 million from a recent rate decision ($12.1 million from rate changes, $20.8 million for the fold-in to base rates of the 1992 sales adjustment revenues, a reduction of $7.7 million in revenue from a separate amortization charge to eliminate the current period revenue effect of rate changes intended to collect sales adjustment revenues booked in prior periods, and the pass through to customers of expense credits of $4.6 million), and $15.9 million from increased retail sales. Retail sales increased by 2.7%, mostly due to a return to more normal summer weather.

The retail revenue increases were offset by anticipated reductions of $20.8 million from the sales adjustment provision and $13.7 million in wholesale capacity revenues. Other operating revenues decreased by $0.3 million. Reductions in wholesale energy revenues of $15.8 million were directly offset by reductions in energy expense.

Other factors affecting sales margin were lower retail fuel expense, increasing margin by $9.4 million, and higher revenue related taxes, decreasing margin by $0.6 million.

Other operation and maintenance expenses, including purchased capacity charges, increased by $10.2 million, or 4.5%, in 1993 relative to 1992. Major generating station overhauls and unscheduled repairs accounted for $5.2 million of this increase. Employment costs increased by $4.0 million, most of which resulted from the adoption of a liability for postretirement benefits other than pensions that the implementation of Statement of Financial Accounting Standards No. 106 requires to be accrued over employees' careers. Purchased capacity charges (cogeneration and Connecticut Yankee power purchases) for 1993 increased by $4.0 million, transmission costs increased by $2.4 million; but other nuclear operation and maintenance expenses decreased by $4.0 million.

Other operating expenses, including income taxes but excluding a 1993 fourth quarter one-time reorganization charge, decreased by $20.3 million in 1993 from 1992, as the effect of accounting treatments ordered in recent rate decisions for recovery of canceled plant, the flow-through to income of certain income tax benefits and lower property taxes more than offset increases in depreciation expense.

Other income declined by $23 million in 1993 from 1992, $9.1 million of which was attributable to the absence of net one-time gains realized in 1992. The remainder was due primarily to an expected decline in deferred revenue and income tax benefits associated with the DPUC's 1992 rate decision, offset, in part, by lower interest charges of $9.3 million. "Net" interest margin (interest income less interest expense) improved by $6.6 million in 1993 over 1992.

OUTLOOK

Revenues for 1995 will increase by $13.1 million compared to 1994 due to the completion of the non-cash amortization of deferred sales adjustment revenues ($7.7 million amortized and collected in rates in 1993 and $13.1 million amortized and collected in rates in 1994). Revenues for 1995 should also increase as a result of an approximate 1% ($6 million) rate increase for recovery, through the Conservation Adjustment Mechanism, of previously recorded and projected conservation costs.

The Company's financial condition will continue to be dependent on the level of retail and wholesale sales. The two primary factors that affect sales volume are economic conditions and weather. A 1% increase in retail sales would increase revenues by $6.0 million and sales margin (revenue less fuel expense and revenue-based taxes) by about $5.0 million. The Company has experienced "real" (nonweather-related) growth in kilowatt-hour sales of approximately 0.7%, on average, per year since 1992. However, a return to normal weather in 1995 could decrease revenues by 0.7%, or $4.5 million (sales margin by $3.4 million). A continuation of the 1992-1994 "real" sales growth trend would be offset by a return to normal weather.

Sales margin should improve further from lower fuel expense in 1995. Higher generating output from the nuclear units (there is currently no planned outage for Seabrook in 1995) and lower nuclear fuel prices could add $3-$4 million to margin if normal operating assumptions are met. However, if the generation level is higher than expected from the Seabrook unit, a refueling outage, currently planned for early in 1996, may move, partially or fully, into 1995.

Taking all of the above factors into account, overall sales margin would be expected to increase in 1995, compared to 1994, by $23-$25 million. These increases will be offset by the commencement of the amortization of Seabrook phase-in costs at $12.6 million after-tax (equivalent, approximately, to a $23 million revenue requirement) per year for five years beginning in 1995.

Another major factor affecting the Company's financial condition will be the Company's ability to control expenses. Operation and maintenance expense is expected to decline by several million dollars in 1995 compared to 1994, due primarily to lower maintenance costs at generating units, the full impact of the Company's 1993 reorganization and early retirement program, and other cost reduction efforts. Anticipated depreciation and property taxes should increase expenses by $4-$5 million in 1995 from 1994 levels.

The Company expects continued reductions in interest expense from the 1994 level of $84 million, to about $79-$80 million at February 1995 interest rate levels. This 1995 interest expense level would be 30% below the 1989 level and would mark the sixth consecutive year of interest expense decline. Similar interest expense reductions are expected for 1996, as well, assuming February 1995 interest rate levels.

A major contingency in the Company's expected earnings for 1995 is the timing of the Seabrook refueling outage. If the refueling outage moves fully into 1995, 1995 sales margin would be reduced by about $2 million, and operations and maintenance expense would be increased by $3-$4 million over currently anticipated amounts. These negative effects on 1995 earnings would affect anticipated 1996 results positively. The Company continues to expect to achieve growth in earnings from operations of 4% annually, on average, from its 1992 level of $3.17 per share.

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.

The electric utility industry is being subjected to increasing competition. Currently, the Company's retail electric service rates are subject to regulation and are based on the Company's costs. Therefore, the Company, and all regulated utilities, are subject to certain accounting standards (Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation") that are not applicable to other businesses in general. These accounting rules allow all regulated utilities, 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 balance sheets for such costs. The effects of competition could cause the operations of the Company, or a portion thereof, to fail to meet the criteria for application of these accounting rules. While the Company expects to continue to meet these criteria in the near future, if the Company were to cease meeting these criteria, accounting standards for business in general would become applicable and immediate recognition of any previously 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 would have a material adverse effect on the Company's earnings and retained earnings in that year and may have a material adverse effect on the Company's ongoing financial condition, as well.

INFLATION

Much of the Company's operating expense structure is based on fixed charges for plant, purchased power, fuel expense and taxes that have no direct relationship to "inflation" as defined by the Producer Price Index (PPI). That portion of fuel expense (fossil fuel expense) which is a factor in the PPI, is subject to a "pass-through" revenue recovery from customers. The operations expense component most sensitive to inflation, wage and benefit costs, account for about 15% of the Company's total operating expenses excluding income taxes.

A significant portion of the "fixed charges for plant" component of operating expenses is based on the historic cost of the Company's generating units. Under current conditions the cost of future additional or replacement generating capacity, if needed, would probably be less than the cost of existing generating capacity.

THE UNITED ILLUMINATING COMPANY
CONSOLIDATED STATEMENT OF INCOME
For the Years Ended December 31, 1994, 1993 and 1992
(Thousands except per share amounts)

	1994	1993	1992
Operating Revenues (Note G)	$656,748	$653,023	$667,325
Operating Expenses			
Operation			
Fuel and energy	127,354	138,050	163,253
Capacity purchased	44,769	47,424	43,560
Reorganization charge	-	13,620	-
Other	151,330	148,332	145,032
Maintenance	41,768	41,475	38,394
Depreciation	58,165	56,287	50,706
Amortization of cancelled nuclear project (Note J)	1,172	1,172	10,415
Amortization of deferred fossil fuel costs	-	608	-
Income taxes (Note A and E)	44,937	33,309	48,712
Property tax settlement	2,536	-	-
Other taxes (Note G)	57,325	57,932	59,231
Total	529,356	538,209	559,303
Operating Income	127,392	114,814	108,022
Other Income and (Deductions)			
Allowance for equity funds used during construction	753	999	1,003
Deferred return - Seabrook Unit 1	-	7,497	15,959
Other-net (Note G)	(1,907)	71	18,545
Non-operating income taxes	3,214	6,322	12,558
Total	2,060	14,889	48,065
Income Before Interest Charges	129,452	129,703	156,087
Interest Charges			
Interest on long-term debt	73,772	80,030	88,666
Other interest (Note G)	10,301	12,260	12,882
Allowance for borrowed funds used during construction	(2,710)	(3,068)	(2,229)
Net Interest Charges	81,363	89,222	99,319
Income Before Cumulative Effect of Accounting Change	48,089	40,481	56,768
Cumulative effect for years prior to 1994 of accounting change for postemployment benefits (net of income taxes of $956) (Note H)	(1,294)	-	-
Net Income	46,795	40,481	56,768
Dividends on Preferred Stock	3,323	4,318	4,338
Income Applicable to Common Stock	$43,472	$36,163	$52,430
Average Number of Common Shares Outstanding	14,085	14,064	13,941
Earnings per share of Common Stock before cumulative effect of accounting change	$3.18	$2.57	$3.76
Cumulative effect for years prior to 1994 of accounting change for postemployment benefits	(0.09)	-	-
Earnings per share of Common Stock	$3.09	$2.57	$3.76
Cash Dividends Declared per share of Common Stock	$2.76	$2.66	$2.56

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, 1994, 1993 and 1992

(Thousands of Dollars)

	1994	1993	1992
Cash Flows From Operating Activities			
Net Income	$46,795	$40,481	$56,768
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	67,336	65,788	70,298
Deferred income taxes	9,541	9,422	31,093
Deferred investment tax credits - net	(762)	(762)	(762)
Gain on sale of facility	-	-	(5,915)
Amortization of nuclear fuel	11,632	21,922	23,440
Cumulative effect for years prior to 1994 of accounting change for postemployment benefits - net	1,294	-	-
Allowance for funds used during construction	(3,463)	(4,067)	(3,232)
Deferred return - Seabrook Unit 1	-	(7,497)	(15,959)
Sales adjustment revenue	13,113	7,668	(6,217)
Changes in:			
Accounts receivable - net	2,840	3,344	(4,637)
Fuel, materials and supplies	(1,140)	(638)	1,481
Prepayments	(7,344)	(1,833)	1,503
Accounts payable	(6,578)	(10,098)	7,672
Interest accrued	(1,046)	(2,431)	(6,918)
Taxes accrued	9,756	1,017	(1,829)
Reorganization charge accrued	-	13,620	-
Other assets and liabilities	(4,989)	9,920	1,851
Total Adjustments	90,190	105,375	91,869
Net Cash Provided by Operating Activities	136,985	145,856	148,637
Cash Flows from Financing Activities			
Common stock	109	1,834	3,442
Long-term debt	-	164,460	247,000
Notes payable	67,000	(84,099)	71,099
Securities redeemed and retired:			
Preferred stock	(15,858)	-	(1,695)
Long-term debt	(117,391)	(143,543)	(214,811)
Expenses of issues	-	(1,742)	(1,453)
Lease obligations	(2,362)	(4,174)	(71,866)
Dividends			
Preferred stock	(3,658)	(4,318)	(4,365)
Common stock	(38,520)	(36,991)	(35,252)
Net Cash used in Financing Activities	(110,680)	(108,573)	(7,901)
Cash Flows from Investing Activities			
Plant expenditures, including nuclear fuel	(63,044)	(94,743)	(66,390)
Proceeds from sale of facility	-	-	6,012
Investment in debt securities	-	94,529	(94,529)
Net Cash used in Investing Activities	(63,044)	(214)	(154,907)
Cash and Temporary Cash Investments:			
Net change for the period	(36,739)	37,069	(14,171)
Balance at beginning of period	48,171	11,102	25,273
Balance at end of period	$11,432	$48,171	$11,102
Cash paid during the period for:			
Interest (net of amount capitalized)	$75,802	$78,021	$82,829
Income taxes	$25,555	$17,435	$12,634

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

THE UNITED ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEET
December 31, 1994, 1993 and 1992

ASSETS
(Thousands of Dollars)

	1994	1993	1992
Utility Plant at Original Cost			
In service	$1,761,627	$1,690,142	$1,631,787
Less, accumulated provision for depreciation	493,482	446,716	407,729
	1,268,145	1,243,426	1,224,058
Construction work in progress	57,669	77,395	59,809
Nuclear fuel	31,443	40,285	52,144
Net Utility Plant	1,357,257	1,361,106	1,336,011
Other Property and Investments	21,824	17,811	13,176
Current Assets			
Cash and temporary cash investments	11,432	48,171	11,102
Short-term investment	-	-	94,529
Accounts receivable			
Customers, less allowance for doubtful accounts of $4,900, $4,700 and $3,900	61,042	62,703	56,796
Other	26,981	28,160	37,411
Accrued utility revenues	23,139	22,765	24,389
Fuel, materials and supplies, at average cost	22,318	21,178	20,540
Prepayments	12,307	4,963	3,130
Other	90	41	57
Total	157,309	187,981	247,954
Regulatory Assets *(future amounts due from customers through the ratemaking process)*			
Income taxes due principally to book-tax differences (Note A)	403,132	408,272	406,258
Deferred return - Seabrook Unit 1	62,929	62,929	55,432
Unamortized cancelled nuclear projects	25,792	26,964	28,136
Unamortized redemption costs	26,269	32,573	28,186
Sales adjustment revenues	-	13,113	20,781
Uranium enrichment decommissioning costs	1,540	1,600	-
Deferred fossil fuel costs	112	198	1,109
Unamortized debt issuance expenses	5,527	6,631	6,474
Other	13,300	15,114	10,117
Total	538,601	567,394	556,493
	$2,074,991	$2,134,292	$2,153,634

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

THE UNITED ILLUMINATING COMPANY
CONSOLIDATED BALANCE SHEET
December 31, 1994, 1993 and 1992

CAPITALIZATION AND LIABILITIES

(Thousands of Dollars)

	1994	1993	1992
Capitalization (Note B)			
Common stock equity			
Common stock	$284,133	$284,028	$282,433
Paid-in capital	738	734	495
Capital stock expense	(2,402)	(3,163)	(3,163)
Retained earnings	145,559	141,725	142,981
	428,028	423,324	422,746
Preferred stock	44,700	60,945	60,945
Long-term debt	708,340	875,268	893,457
Total	1,181,068	1,359,537	1,377,148
Noncurrent Liabilities			
Obligations under capital leases	17,799	19,871	23,855
Uranium enrichment decommissioning reserve	1,337	1,486	-
Nuclear decommissioning obligation	7,628	5,606	-
Other	2,517	2,156	1,998
Total	29,281	29,119	25,853
Current Liabilities			
Current portion of long-term debt	193,133	143,333	92,833
Notes payable	67,000	-	84,099
Accounts payable	42,846	49,424	59,522
Dividends payable	10,467	10,445	10,017
Taxes accrued	16,607	6,851	5,834
Pensions accrued (Note H)	30,177	33,547	18,714
Interest accrued	20,926	21,972	24,403
Obligations under capital leases	1,169	1,838	2,028
Other accrued liabilities	30,069	26,813	12,953
Total	412,394	294,223	310,403
Customers' Advances for Construction	2,628	2,667	2,672
Regulatory Liabilities *(future amounts owed to customers through the ratemaking process)*			
Accumulated deferred investment tax credits	18,671	19,433	20,195
Deferred gain on sale of utility plant	276	2,070	3,391
Other	1,820	1,837	-
Total	20,767	23,340	23,586
Deferred Income Taxes *(future tax liabilities owed to taxing authorities)*	428,853	425,406	413,972
Commitments and Contingencies	-	-	-
	$2,074,991	$2,134,292	$2,153,634

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

THE UNITED ILLUMINATING COMPANY
CONSOLIDATED STATEMENT OF RETAINED EARNINGS
For the Years Ended December 31, 1994, 1993 and 1992
(Thousands of Dollars)

	1994	1993	1992
Balance, January 1	$141,725	$142,981	$125,448
Net Income	46,795	40,481	56,768
Adjustments associated with repurchase of preferred stock	(761)	-	796
Total	187,759	183,462	183,012
Deduct Cash Dividends Declared			
Preferred stock	3,323	4,318	4,338
Common stock	38,877	37,419	35,693
Total	42,200	41,737	40,031
Balance, December 31	$145,559	$141,725	$142,981

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(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).

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 obligation relieved in the future through the ratemaking process.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, United Resources Inc., United Energy International, Inc. and Research Center, Inc. Intercompany accounts and transactions have been eliminated in consolidation.

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, 1994, 1993 and 1992 is comprised as follows:

	1994	1993	1992
Production	$1,114,755	$1,104,156	$1,083,247
Transmission	143,984	129,186	126,211
Distribution	364,102	334,251	319,409
General	43,600	41,009	42,065
Future use plant	31,853	29,221	26,537
Other	63,333	52,319	34,318
	$1,761,627	$1,690,142	$1,631,787

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 semi-annually the allowance applicable to major construction projects. Weighted average AFUDC rates in effect for 1994, 1993 and 1992 were 8.19%, 8.75% and 10.25%, 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 1994, 1993 and 1992 were equivalent to approximately 3.27%, 3.22% and 3.15%, respectively, of the original cost of depreciable property.

Income Taxes

Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 109 "Accounting for Income Taxes". In accordance with SFAS No. 109, 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 net regulatory asset that reflects anticipated future recovery in rates of these deferred tax provisions.

For ratemaking purposes, the Company practices full normalization for 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 Cash Equivalents

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 equivalents. 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 $2.3 million, $3.4 million and $2.9 million, at December 31, 1994, 1993 and 1992, respectively.

Investments

The Company's investment in the Connecticut Yankee Atomic Power Company joint venture, a nuclear generating company in which the Company has a 9 1/2% stock interest, is accounted for on an equity basis. This investment amounted to $9.6 million, $9.5 million and $9.4 million at December 31, 1994, 1993 and 1992, respectively.

Fossil Fuel Costs

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 is 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 rate-making treatment of the Company's existing deferred fossil fuel cost balances.

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.

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".

Prior to January 1, 1993, the Company accounted for other postemployment benefits, consisting principally of health and life insurance, on a pay-as-you-go basis. Effective January 1, 1993, the Company commenced accounting for these costs 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 accounting change has been allowed in retail rates in accordance with a 1992 rate decision of the DPUC.

Effective January 1, 1994, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 112, "Employers' Accounting for Postemployment Benefits." This statement establishes accounting standards for employers who provide benefits, such as unemployment compensation, severance benefits and disability benefits to former or inactive employees after employment but before retirement and requires recognition of the obligation for these benefits. The effect of adopting this statement is reported as a change in accounting principle and decreased earnings for common stock for 1994 by $1.3 million or $.09 per share.

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 th 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, 1994, the Company's unfunded share of the obligation, based on its ownership interest in Seabrook Unit 1 and Millstone Unit 3, was approximately $1.3 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 $1,727,000, $1,616,000 and $1,334,000 during 1994, 1993 and 1992 into the decommissioning trust funds for Seabrook Unit 1 and Millstone Unit 3. At December 31, 1994, the Company's share of the trust fund balances, which include accumulated earnings on the funds, were $5.2 million and $2.4 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 "Noncurrent Liabilities" on the Company's Consolidated Balance Sheet.

(B) CAPITALIZATION

	December 31,					
	1994		1993		1992	
	Shares Outstanding	\$(000's)	Shares Outstanding	\$(000's)	Shares Outstanding	\$(000's)
Common Stock Equity						
Common stock, no par value, at December 31(a)	14,086,691	\$284,133	14,083,291	\$284,028	14,033,148	\$282,433
Shares authorized						
1992 30,000,000						
1993 30,000,000						
1994 30,000,000						
Paid-in capital		738		734		495
Capital stock expense		(2,402)		(3,163)		(3,163)
Retained earnings (b)		145,559		141,725		142,981
Total common stock equity		428,028		423,324		422,746
Preferred and Preference Stock (c)						
Cumulative preferred stock, \$100 par value, shares authorized at December 31,						
1992 1,259,455						
1993 1,259,455						
1994 1,247,005						
Preferred stock issues:						
4.35% Series A	40,425		40,425		40,425	
4.72% Series B	48,280		50,730		50,730	
4.64% Series C	32,100		32,100		32,100	
5 5/8% Series D	51,200		61,200		61,200	
7.60% Series E	125,000		125,000		125,000	
7.60% Series F	150,000		150,000		150,000	
	447,005	44,700	459,455	45,945	459,455	45,945
Cumulative preferred stock, \$25 par value, shares authorized at December 31,						
1992 2,400,000						
1993 2,400,000						
1994 2,400,000						
Preferred stock issues:						
8.80% 1976 Series	-	-	600,000	15,000	600,000	15,000
Cumulative preference stock, \$25 par value, shares authorized at December 31,						
1992 5,000,000						
1993 5,000,000						
1994 5,000,000						
Preference stock issues	-	-	-	-	-	-
Total preferred stock not subject to mandatory redemption		44,700		60,945		60,945

	December 31,		
	1994 $(000's)	1993 $(000's)	1992 $(000's)
Long-term Debt (d)			
First Mortgage Bonds:			
9.44%, Series B, maturing serially as to $10,800 principal amount on February 15 in each of the years 1995 to 1999.	$54,000	$54,000	$54,000
10.32%, Series C, maturing serially as to $55,333 principal amount on January 15, 1995	55,333	110,666	166,000
Other Long-term Debt			
Pollution Control Revenue Bonds:			
14 1/2%, 1984 Series, due October 1, 2009	-	110	40,000
14 1/2%, 1984 Series B, due December 1, 2009	-	3,830	28,400
9 1/2%, 1986 Series, due June 1, 2016	7,500	7,500	7,500
9 3/8%, 1987 Series, due July 1, 2012	25,000	25,000	25,000
10 3/4%, 1987 Series, due November 1, 2012	43,500	43,500	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	-
Solid Waste Disposal Revenue Bonds:			
Adjustable rate 1990 Series A due September 1, 2015	30,000	30,000	30,000
Notes:			
7.62%, 1991 Series A, due September 12, 1994	-	30,000	30,000
7.20%, 1991 Series B, due November 1, 1994	-	13,000	13,000
6.82%, 1991 Series C, due December 2, 1994	-	10,000	10,000
6.00%, 1992 Series D, due January 15, 1995	50,000	50,000	50,000
7.00%, 1992 Series E, due January 15, 1997	50,000	50,000	50,000
7.25%, 1992 Series F, due October 2, 1995	47,000	47,000	47,000
7 3/8%, 1992 Series G, due January 15, 1998	100,000	100,000	100,000
6.20%, 1993 Series H, due January 15, 1999	100,000	100,000	-
Long-term bank loans	-	5,000	17,500
Obligation under the Seabrook Unit 1 sale/leaseback agreement	250,000	250,000	250,000
	901,793	1,019,066	986,900
Unamortized debt discount less premium at December 31, 1994, 1993 & 1992	(320)	(465)	(610)
Total long-term debt	901,473	1,018,601	986,290
Less current portion included in Current Liabilities (d)	193,133	143,333	92,833
Total long-term debt included in Capitalization	708,340	875,268	893,457
Total Capitalization	$1,181,068	$1,359,537	$1,377,148

(a) Common Stock

The Company issued 3,400 shares of common stock in 1994, 46,000 shares of common stock in 1993 and 100,800 shares of common stock in 1992 pursuant to a stock option plan. During 1993, the Company also issued 4,143 shares of common stock pursuant to a long-term incentive program.

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. On June 5, 1991, the DPUC 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 203,200 shares of stock at an exercise price of $30.75 per share, 2,800 shares of stock at an exercise price of $28.3125 per share, 1,800 shares of stock at an exercise price of $31.1875 per share, 4,000 shares of stock at an exercise price of $35.625 per share, 36,200 shares of stock at an exercise price of $39.5625 per share, 5,000 shares of stock at an exercise price of $42.375 per share and 18,600 shares of stock at an exercise price of $30 per share have been granted by the Board of Directors and remain outstanding at December 31, 1994. Options to purchase 98,000 shares of stock at an exercise price of $30.75 and 2,800 shares of stock at an exercise price of $28.3125 were exercised during 1992. Options to purchase 42,000 shares of stock at an exercise price of $30.75 per share, 1,400 shares of stock at an exercise price of $28.3125 per share, 1,200 shares of stock at an exercise price of $31.1875 per share and 1,000 shares of stock at an exercise price of $35.625 per share were exercised in 1993. Options to purchase 3,400 shares of stock at an exercise price of $30.75 per share were exercised during 1994.

(b) Retained Earnings Restriction

The indenture under which the Company's 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 $87.2 million were free from such limitations at December 31, 1994.

(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 1992, the Company purchased and cancelled 16,950 shares of its $100 par value 4.72% Preferred Stock, Series B, at a discount, resulting in a non-taxable addition to common equity of approximately $797,000.

There was no redemption of preferred stock in 1993.

On April 15, 1994, the Company redeemed all of the 600,000 outstanding shares of its 8.80% Preferred Stock, 1976 Series, at $25.25 per share plus accrued dividends.

In July 1994, the Company purchased 2,450 shares of its 4.72% $100 par value Preferred Stock, Series B, at a discount, resulting in a non-taxable gain of $116,000.

In December 1994, the Company purchased 10,000 shares of its 5 5/8% $100 par value Preferred Stock, Series D, at a discount, resulting in a non-taxable gain of $420,000.

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 some other event of default occurs, preferred shareholders are entitled to elect a majority of the Board of Directors until all preferred dividend arrears 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, 1994.

(d) Long-Term Debt

In January 1994, the Company repaid $55.3 million principal amount of maturing 10.32% First Mortgage Bonds of Bridgeport Electric Company, a wholly-owned subsidiary of the Company that was subsequently merged with and into the Company, and a $5 million 13.1% term loan. These repayments were made with a portion of the net proceeds from the issuance and sale, in December 1993, of $100 million five-year and one month Notes at a coupon rate of 6.20%.

On September 12, 1994, the Company repaid at maturity $30 million principal amount of 7.62% Notes. In addition, on November 1, 1994, December 2, 1994 and January 17, 1995, the Company repaid at maturity $13 million, $10 million and $50 million principal amounts of 7.20%, 6.82% and 6.0% Notes, respectively.

On October 1, 1994 and December 1, 1994, the Company redeemed the remaining $110,000 and $3,830,000 principal amounts of 14 1/2% 1984 Series, and 14 1/2% 1984 Series B, Pollution Control Revenue Bonds, respectively, at a 3% premium.

On January 17, 1995 and February 15, 1995, the Company repaid $55.3 million and $10.8 million principal amounts of maturing 10.32% and 9.44% First Mortgage Bonds of Bridgeport Electric Company, a wholly-owned subsidiary of the Company that was merged with and into the Company in September of 1994.

On August 18, 1994, United Capital Funding Partnership L.P. ("United Capital"), a special purpose limited partnership in which the Company owns all of the general partner interests, was formed for the sole purpose of issuing its limited partner interests, represented by Preferred Capital Securities ("Capital Securities"), and lending the proceeds thereof to the Company in return for Junior Subordinated Deferrable Interest Debentures ("Subordinated Debentures"). United Capital and the Company have registered $100 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. The Company has also registered $200 million principal amount of Notes for sale to the public from time to time, in one or more series, under the Securities Act of 1933.

Maturities and mandatory redemptions/repayments and annual interest expense on existing long-term debt are set forth below:

	1995	1996	1997 (000's)	1998	1999
Long-term debt (beginning of period)(1)	$871,793	$708,660	$695,890	$630,719	$515,157
Less:					
Maturities	97,000	-	50,000	100,000	100,000
Mandatory redemptions/repayments	66,133	12,770	15,171	15,562	15,988
Long-term debt (end of period)(1)(2)	$708,660	$695,890	$630,719	$515,157	$399,169
Annual interest associated with existing outstanding debt (1)(2)	$ 59,637	$ 55,221	$ 50,838	$ 42,930	$ 40,647
Annual amortization of issuance expense and repurchase premiums associated with existing debt	$5,451	$3,167	$2,893	$2,543	$1,189

(1) Does not include $30 million of tax-exempt adjustable rate Solid Waste Disposal Revenue Bonds, 1990 Series A, due September 1, 2015, classified on the Company's books as a current liability (interest rate for March 1995 to September 1995 is 4.50%).
(2) Does not include interest on any new financings that may be required to fund maturities, redemptions or plant additions in any given year. The Company expects some new financings to occur.

(C) RATE-RELATED REGULATORY PROCEEDINGS

On December 16, 1992, the DPUC approved levelized rate increases of 2.66% ($15.8 million) in 1993 and 2.66% (an additional $17.3 million) in 1994, including allowed conservation and load management program revenue increases. However, the Company has realized increased revenues of $12.1 million and $12.5 million in 1993 and 1994, respectively, as a result of these rate increases.

Utilities are entitled by Connecticut law to revenues sufficient to allow them to cover their operating and capital costs, to attract needed capital and maintain their financial integrity, while also protecting the public interest. Accordingly, the DPUC's 1992 rate decision authorized a return on equity of 12.4% for ratemaking purposes. However, the Company may earn up to 1% above this level before a mandatory review is required by the DPUC.

The Company is allowed revenue increases for conservation and load management expenditures through a Conservation Adjustment Mechanism (CAM) in its retail rates, and accordingly expects a revenue increase in 1995 of $6 million, or 1%, through operation of the CAM. Except for CAM revenue increases, the Company has stated publicly that it does not plan to seek any retail rate increases for the foreseeable future.

Since January 1971, UI has had a fossil fuel adjustment clause (FCA) in virtually all of its retail rates. The DPUC is required by law to convene an administrative proceeding prior to approving FCA charges or credits for each month. The law permits automatic implementation of the charges or credits if the DPUC fails to act within five days of the administrative proceeding, although all such charges and credits are also subject to further review and appropriate adjustment by the DPUC at public hearings required to be held at least every three months. The

DPUC has made no material changes in UI's FCA charges and credits as the result of any of these proceedings or hearings.

(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 has been allowed to record a deferred return on the portion of allowable investment excluded from rate base during the phase-in period. The accumulated deferred return has been added to rate base each year since January 1, 1991 in the same proportion as the phase-in installment for that year has borne to the portion of the $640 million remaining to be phased-in. On January 1, 1994, the Company phased into rate base the remaining $74.5 million of allowable investment, plus the remaining $28.2 million of accumulated deferred return. At December 31, 1993, the Company had recorded $62.9 million of accumulated deferred return and no additional deferred return on Seabrook Unit 1 was recognized in income during 1994. The Company will amortize the accumulated deferred return over a five-year period commencing January 1, 1995.

(E) INCOME TAXES

	1994	1993	1992
Income tax expense consists of:		(000's)	
Income tax provisions:			
Current			
Federal	$24,190	$13,484	$6,815
State	8,754	4,843	2,645
Total current	32,944	18,327	9,460
Deferred			
Federal	11,123	9,620	16,860
State	(2,538)	(198)	14,233
Total deferred	8,585	9,422	31,093
Investment tax credits	(762)	(762)	(4,399)
Total income tax expense	$40,767	$26,987	$36,154
Income tax components charged as follows:			
Operating expenses	$44,937	$33,309	$48,712
Other income and deductions - net	(3,214)	(6,322)	(12,558)
Cumulative effect of change in accounting for postemployment benefits	(956)	-	-
Total income tax expense	$40,767	$26,987	$36,154
The following table details the components of the deferred income taxes:			
Accelerated depreciation	$11,526	$11,318	$15,452
Tax depreciation on unrecoverable plant investment	8,170	7,915	9,378
Conservation & load management	1,897	3,084	3,995
Property tax adjustment	(1,991)	(1,991)	(1,991)
Deferred fossil fuel costs	(37)	(381)	490
Seabrook sale/leaseback transaction	(2,039)	(2,016)	1,629
Premiums on BEC bond redemption	(1,619)	(2,378)	(3,209)
Cancelled nuclear projects	(467)	(467)	(3,795)
Alternative minimum tax	-	(139)	(1,344)
Sales adjustment revenues	(5,553)	(3,248)	2,415
Gains on sale of utility plant	-	-	1,237
Pension benefits	148	(6,641)	(2,489)
Postretirement benefits	169	(538)	-
Postemployment benefits	(956)	-	-
Other - net	(663)	4,904	9,325
Deferred income taxes - net	$8,585	$9,422	$31,093

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:

	1994		1993		1992	
	Pre-Tax	Tax	Pre-Tax	Tax	Pre-Tax	Tax
			(000's)			
Computed tax at federal statutory rate		$30,646		$23,614		$31,593
Increases (reductions) resulting from:						
Deferred return-Seabrook Unit 1	-	-	($7,497)	(2,624)	($15,959)	(5,426)
ITC taken into income	(762)	(762)	(762)	(762)	(4,399)	(4,399)
Allowance for equity funds used during construction	(753)	(263)	(999)	(349)	(1,003)	(341)
Tax exempt interest on municipal bonds	-	-	(283)	(99)	(3,664)	(1,246)
Book depreciation in excess of non-normalized tax depreciation	20,625	7,218	21,711	7,599	20,182	6,862
State income taxes, net of federal income tax benefits	6,216	4,040	4,645	3,019	16,878	11,140
Other items - net	(320)	(112)	(9,746)	(3,411)	(5,968)	(2,029)
Total income tax expense		$40,767		$26,987		$36,154
Book Income Before Federal Income Taxes		$87,561		$67,467		$92,921
Effective income tax rates		46.6%		40.0%		38.9%

At December 31, 1994, the Company had deferred tax liabilities for taxable temporary differences of $572 million and deferred tax assets for deductible temporary differences of $143 million, resulting in a net deferred tax liability of $429 million. Significant components of deferred tax liabilities and assets were as follows: tax liabilities on book/tax plant basis differences, $225 million; tax liabilities on the cumulative amount of income taxes on temporary differences previously flowed through to ratepayers, $162 million; tax liabilities on normalization of book/tax depreciation timing differences, $101 million and tax assets on the disallowance of plant costs, $69 million.

The Tax Reform Act of 1986 provides for a more comprehensive corporate alternative minimum tax (AMT) for years beginning after 1986. To the extent that the AMT exceeds the federal income tax computed at statutory rates, the excess must be paid in addition to the regular tax liability. For tax purposes, the excess paid in any year can be carried forward indefinitely and offset against any future year's regular tax liability in excess of that year's tentative AMT. The AMT carryforward at December 31, 1994, 1993 and 1992 was $11.4 million, $11.4 million and $11.3 million, respectively.

(F) SHORT-TERM CREDIT ARRANGEMENTS

The Company has a revolving credit agreement with a group of banks, which currently extends to December 14, 1995. The borrowing limit of this facility is $225 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, 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, 1994, the Company had $67 million in short-term borrowings outstanding under this facility.

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, 1994, this coverage ratio was 2.86.

Information with respect to short-term borrowings is as follows:

	1994	1993 (000's)	1992
Maximum aggregate principal amount of short-term borrowings outstanding at any month-end	$75,000	$94,635	$84,099
Average aggregate short-term borrowings outstanding during the year*	$57,000	$73,700	$43,055
Weighted average interest rate*	4.8%	4.1%	4.4%
Principal amounts outstanding at year-end	$67,000	$0	$84,099
Annualized interest rate on principal amounts outstanding at year-end	6.7%	N/A	5.1%

*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 $250,400, $259,600 and $208,400 paid during 1994, 1993 and 1992, respectively, are excluded from the calculation of the weighted average interest rate.

THE UNITED ILLUMINATING COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (continued)

(G) SUPPLEMENTARY INFORMATION

	1994	1993 (000's)	1992
Operating Revenues			
Retail - Base rates	$618,868	$603,559	$566,955
Sales provision adjustment	-	-	21,031
Wholesale - capacity	7,162	6,575	20,315
- energy	27,765	39,356	55,169
Other	2,953	3,533	3,855
Total Operating Revenues	$656,748	$653,023	$667,325
Other Income and (Deductions) - net			
Interest and dividend income	$2,520	$3,568	$6,681
Seabrook funding adjustments	-	-	7,506
Earnings of subsidiaries and Connecticut Yankee	(2,843)	(3,207)	(381)
Amortization of loss on investment in tax-exempt bonds	-	-	(1,752)
Gain on sale of property	63	710	5,921
Engineering study costs	(1,200)	-	-
Miscellaneous other income and (deductions) - net	(447)	(1,000)	570
Total Other Income and (Deductions) - net	($1,907)	$71	$18,545
Other Taxes			
Charged to:			
Operating:			
State gross earnings	$27,403	$27,955	$27,362
Local real estate and personal property	26,318	24,449	26,339
Payroll taxes	6,137	5,525	5,527
Other	3	3	3
	59,861	57,932	59,231
Nonoperating and other accounts	41	335	837
Total Other Taxes	$59,902	$58,267	$60,068
Other Interest Charges			
Notes Payable	$2,713	$3,049	$2,120
Amortization of debt expense and repurchase premiums	6,570	7,818	8,898
Other	1,018	1,393	1,864
Total Other Interest Charges	$10,301	$12,260	$12,882

(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 1994, 1993 and 1992 were $4,028,000, $14,966,000 and $5,749,000, respectively.

The Company's funding policy for the qualified plan is to make annual contributions that satisfy the minimum funding requirements of ERISA but which 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 accordance with this policy, the Company contributed $3.3 million in 1994 for 1993 funding requirements. In addition, the Company contributed $3.9 million in 1994 for 1994 funding requirements. Previously, due to the application of the full funding limitation under ERISA, the Company had not been required to make a contribution since 1985. The supplemental plan is unfunded.

The qualified plan's irrevocable trust fund consists principally of equity and fixed-income securities and real estate investments in approximately the following percentages:

Asset Category	Percentage of Total Fund
Equity Securities	64.1
Fixed-income Securities	30.2
Real Estate	5.7

	1994	1993
	(000's)	
The components of net pension costs were as follows:		
Service cost of benefits earned during the period	$ 4,822	$ 3,977
Interest cost on projected benefit obligation	15,023	13,165
Actual return on plan assets	(1,218)	(23,344)
Net amortization and deferral	(14,095)	10,130
Net pension cost	$ 4,532*	$ 3,928**

*In addition, an adjustment of $504,000 was recorded due to an overaccrual of the cost of special termination benefits in 1993.

**In addition, a cost of $11,038,000 was recognized under SFAS No. 88 as a result of special termination benefits provided under the Pension Plan.

	1994	1993
Assumptions used to determine pension costs were:		
Discount rate	7.50%	8.25%
Average wage increase	5.50%	5.50%
Return on plan assets	9.00%	8.50%

	December 31, 1994		December 31, 1993	
	Qualified Plan	Non-Qualified Plans	Qualified Plan	Non-Qualified Plans
		(000's)		
The funded status and amounts recognized in balance sheets are as follows:				
Actuarial present value of benefit obligations:				
Vested benefit obligation	$125,289	$3,548	$130,582	$3,097
Accumulated benefit obligation	$130,758	$3,548	$137,081	$3,097
Reconciliation of accrued pension liability:				
Projected benefit obligation	$183,951	$4,510	$198,236	$4,262
Less fair value of plan assets	165,788	-	167,732	-
Projected benefit greater (less) than plan assets	18,163	4,510	30,504	4,262
Unrecognized prior service cost	(5,619)	(397)	(6,516)	(157)
Unrecognized net gain (loss) from past experience	1,849	-	(6,966)	(327)
Unrecognized net asset (obligation) at date of initial application	11,770	(99)	12,878	(131)
Accrued pension liability	$ 26,163	$4,014	$29,900	$3,647
Assumptions used in estimating benefit obligations:				
Discount rate	8.50%	8.50%	7.50%	7.50%
Average wage increase	5.50%	5.50%	5.50%	5.50%

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.

Prior to January 1, 1993, the Company recognized the cost of providing OPEB on a pay-as-you-go basis by expensing the annual insurance premiums. Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", which requires, among other things, that OPEB costs be recognized over the employment period that encompasses eligibility to receive such benefits. In its December 16, 1992 decision on the Company's application for retail rate relief, the DPUC recognized the Company's obligation to adopt SFAS No. 106, effective January 1, 1993, and approved the Company's request for revenues to recover OPEB expenses on a SFAS No. 106 basis. A portion of these expenses represents the transition obligation, which will accrue over a 20-year period, representing the future liability for medical and life insurance benefits based on past service for retirees and active employees.

For funding purposes, the Company established a Voluntary Employees' Benefit Association Trust (VEBA) to fund OPEB for union employees who retire on or after January 1, 1994. Approximately 52% 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, excluding the amount that resulted from the reorganization minus pay-as-you-go benefit payments for pre-January 1, 1994 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 $3 million and $1.8 million to the union VEBA on December 30, 1993 and December 29, 1994, respectively. During 1994, the Company contributed approximately $2.2 million to the 401(h) account. The Company currently plans to fund the portion of the OPEB expense that is related to the reorganization during the years 1994-1996.

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

	1994	1993
	(000's)	
Service cost	$1,372	$1,182
Interest cost	2,534	1,959
Actual return on plan assets	72	-
Amortizations and deferrals - net	1,346	1,215
Net Cost of Postretirement Benefit	$5,324	$4,356

Assumptions used to determine OPEB costs were:

	1994	1993
Discount rate	7.5%	8.25%
Health Care Cost Trend Rate*	7.7%	**

*Assumed rates gradually decline to 6.2% by the year 2020
**Assumed rate for Pre-age 65 claims - 8.3% and for Post-age 65 claims - 9.0%

A one percentage point increase in the assumed health care cost trend rate would have increased the service cost and interest cost components of the 1994 net cost of periodic postretirement benefit by approximately $599,000 and would increase the accumulated postretirement benefit obligation for health care benefits by approximately $3,525,000.

The following table reconciles the funded status of the plan with the amount recognized in the Consolidated Balance Sheet as of December 31, 1994 and 1993:

	1994	1993
	(000's)	
Accumulated Postretirement Benefit Obligation:		
Retirees	$ 13,028	$12,292
Fully eligible active plan participants	7,078	1,950
Other active plan participants	12,267	16,088
Total Accumulated Postretirement Benefit Obligation	32,373	30,330
Plan assets at fair value	6,781	2,984
Accumulated Postretirement Benefit Obligation in Excess of Plan Assets	25,592	27,346
Unrecognized net loss	(2,958)	(2,990)
Unamortized transition obligation	(21,874)	(23,089)
Accrued Postretirement Benefit Obligation	$ 760	$ 1,267

The weighted average discount rates used to measure the accumulated postretirement benefit obligation at December 31, 1994 and 1993 were 8.5% and 7.5%, respectively.

During 1993, in conjunction with an in-depth organizational review, the Company offered a voluntary early retirement program to non-union employees who were eligible to receive pension benefits. This offer was accepted by 103 employees. The 1993 OPEB cost for this program was $1.3 million. These costs are recognized as a component of the reorganization charge shown on the Company's Consolidated Statement of Income.

Effective January 1, 1994, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 112, "Employers' Accounting for Postemployment Benefits." This statement establishes accounting standards for employers who provide benefits, such as unemployment compensation, severance benefits and disability benefits to former or inactive employees after employment but before retirement and requires recognition of the obligation for these benefits. The effect of adopting this statement is reported as a charge against income in the first quarter of 1994 due to a change in accounting principle. The charge decreased earnings for common stock for 1994 by $1.3 million, after tax, or $.09 per share.

The Company has an Employee Stock Ownership Plan (ESOP) for substantially all its employees. Under the plan, eligible employees received Company common stock and the plan provided certain tax benefits to the Company. Neither the Company nor the employee-participants made any contributions to the ESOP since 1987.

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 to the 401(k) Plan in the form of Company common stock for each participant. The matching contribution currently equals fifty cents for each dollar of the participant's compensation deferred, but is not more than three percent of the participant's annual salary. The Company's matching contributions to the 401(k) Plan during 1994, 1993 and 1992 were $1.6 million, $1.3 million and $.9 million, respectively.

(I) JOINTLY OWNED PLANT

At December 31, 1994, the Company had the following interests in jointly owned plants:

	Ownership/ Leasehold Share	Plant In Service	Accumulated Depreciation
		(Millions)	
Seabrook Unit 1	17.5 %	$654	$81
Millstone Unit 3	3.685	133	50
New Haven Harbor Station	93.7	132	63

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 nuclear generating unit under construction 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.

(K) FUEL FINANCING OBLIGATIONS AND OTHER LEASE OBLIGATIONS

The Company has a Fossil Fuel Supply Agreement with a financial institution providing for financing up to $37.5 million in fossil fuel purchases. Under this agreement, the financing entity acquires and stores natural gas, coal and fuel oil for sale to the Company, and the Company purchases 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 1996. At December 31, 1994, approximately $10.7 million of fossil fuel purchases were being financed under this agreement.

The Company has leases (some of which are capital leases), including arrangements for data processing and office equipment, vehicles, office space and oil tanks. The gross amount of assets recorded under capital leases and the related obligations of those leases as of December 31, 1994 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:

	(000's)
1995	$ 2,666
1996	1,715
1997	1,715
1998	1,715
1999	1,696
After 1999	22,783
Total minimum capital lease payments	32,290
Less: Amount representing interest	13,322
Present value of minimum capital lease payments	$18,968

In January 1994, the Company renegotiated a lease agreement for a service facility. Since the effect of renegotiating the lease, which continues to be treated as a capital lease, was a noncash financing activity during 1994, it is not reflected in the Consolidated Statement of Cash Flows.

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.

Rental payments charged to operating expenses in 1994, 1993 and 1992 amounted to $12.1 million, $14.1 million and $14.8 million, respectively.

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:

	(000's)
1995	$ 4,729
1996	5,317
1997	5,826
1998	6,125
1999	6,426
2000-2012	121,857
Total	$150,280

(L) COMMITMENTS AND CONTINGENCIES

Capital Expenditure Program

The Company has entered into certain commitments in connection with its continuing capital expenditure program. This program is presently estimated at approximately $357.5 million, excluding AFUDC, for 1995 through 1999.

Seabrook

On February 28, 1991, EUA Power Corporation (EUA Power), the holder of a 12.1% ownership share in Seabrook, commenced a proceeding under Chapter 11 of the Bankruptcy Code. EUA Power, a wholly-owned subsidiary of Eastern Utilities Associates (EUA), was organized solely for the purpose of acquiring an ownership share in Seabrook and selling in the wholesale market its share of the electric power produced by Seabrook. EUA Power commenced this bankruptcy proceeding because the cash generated by its sales of power at current market prices was insufficient to pay its obligations on its outstanding debt. Subsequently, EUA Power's name was changed to Great Bay Power Corporation (Great Bay). During 1994, the bankruptcy court confirmed a reorganization plan for Great Bay, which was financed by the injection of $35 million of new ownership equity into this corporation. On November 23, 1994, when this financing was completed, the Company was repaid $5.7 million, representing all advance Seabrook operating expense payments it had made, pending the reorganization plan's becoming effective.

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 $75.5 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 $75.5 million, or $3.775 million. The maximum assessment is adjusted at least every five years to reflect the impact of inflation. Based on its interests in nuclear generating units, the Company estimates its maximum liability would be $23.2 million per incident. However, assessment would be limited to $3.1 million per incident, per year. With respect to each of the operating 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.

The NRC requires nuclear generating units 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 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.

Other Commitments and Contingencies

Hydro-Quebec

The Company is a participant in the Hydro-Quebec transmission intertie facility linking New England and Quebec, Canada. Phase II of this facility, in which UI has a 5.45% participating share, has increased the capacity value of the intertie from 690 megawatts to a maximum of 2000 megawatts. 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. The Company is obligated to furnish a guarantee for its participating share of the debt financing for the Phase II facility. Currently, the Company's guarantee liability for this debt amounts to approximately $9.2 million.

Reorganization Charge

During 1993, the Company undertook an in-depth organizational review with the primary objective of improving customer service. As a result of this review, the Company eliminated approximately 75 positions in a corporate reorganization.

In conjunction with this review and reorganization, the Company offered a voluntary early retirement program to non-union employees who were eligible to receive pension benefits. The early retirement offer was accepted by 103 employees and the Company incurred a one-time charge to 1993 earnings of approximately $13.6 million ($7.8 million, after-tax). The employees who accepted the offer retired during 1994.

All non-retiring employees affected by the corporate reorganization were placed in regular positions or assigned to special projects.

During 1994, the Company realized savings of approximately $2.8 million ($1.6 million, after-tax) as a result of the corporate reorganization and expects annual savings, beginning in 1995, to be approximately $7.9 million ($4.6 million, after-tax).

Site Remediation Costs

The Company has estimated that the cost of environmental remediation of its decommissioned Steel Point Station property in Bridgeport will be approximately $11.3 million, and that the value of the property following remediation will not exceed $6 million. In its December 16, 1992 decision on UI's application for retail rate increases, the DPUC provided for additional revenues to be recovered from customers in the amount of $4.3 million of the difference during the period 1993-1996, 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.

Property Taxes

On November 2, 1993, the Company received "updated" personal property tax bills from the City of New Haven (the City) for the tax year 1991-1992, aggregating $6.6 million, based on an audit by the City's tax assessor. On May 7, 1994, the Company received a "Certificate of Correction....to correct a clerical omission or mistake" from the City's tax assessor relative to the assessed value of the Company's personal property for the tax year 1994-1995, which certificate purports to increase said assessed value by approximately 53% above the tax assessor's valuation at February 28, 1994. The Company is contesting each of these actions of the City's tax assessor vigorously, and has commenced actions in the Superior Court to enjoin the City from any effort to collect the "updated" personal property tax bills for the tax year 1991-1992 and challenging both the May 7, 1994 "Certificate of Correction" and the tax assessor's valuation at February 28, 1994. In December of 1994, the City's tax assessor conducted hearings regarding the assessed value of the Company's personal property for the tax years 1992-1993 and 1993-1994; and the Company anticipates that the City will take some action to revalue the Company's personal property for those tax years. On March 1, 1995, the Company received from the City notices of assessment changes, increasing the assessed valuation of the Company's personal property for the tax year 1995-1996 by 48% over the valuation declared by the Company. The Company expects to take the legal actions necessary to challenge these increases. It is the present opinion of the Company that the ultimate outcome of this dispute will not have a significant impact on the financial position of the Company.

Environmental Concerns

In complying with existing environmental statutes and regulations and further developments in these and other areas of environmental concern, including legislation and studies in the fields of water and air quality (particularly "air toxics", "ozone non-attainment" 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 Company believes that any additional costs incurred for these purposes will be recoverable through the ratemaking process. The total amount of these expenditures is not now determinable.

(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, beginning in 1998, 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 is to take title to and dispose of the utilities' high level wastes and spent nuclear fuel beginning no later than 1998. However, the DOE has announced that its first high level waste repository will not be in operation earlier than 2010, 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.

Until the federal government begins receiving such materials in accordance with the Nuclear Waste Policy Act, operating nuclear generating units will need to retain high level wastes and spent fuel on-site or make other provisions for their storage. Storage facilities for Millstone Unit 3 are expected to be adequate for the projected life of the unit. Storage facilities for the Connecticut Yankee unit are expected to be adequate through the mid-1990s. Storage facilities for Seabrook Unit 1 are expected to be adequate until at least 2010. Fuel consolidation and compaction technologies are being developed and are expected to provide adequate storage capability for the projected lives of the latter two units. In addition, other licensed technologies, such as dry storage casks, can accommodate spent fuel storage requirements.

Disposal costs for low-level radioactive wastes (LLW) that result from normal operation of nuclear generating units have increased significantly in recent years and are expected to continue to rise. The cost increases are functions of increased packaging and transportation costs and higher fees and surcharges charged by the disposal facilities. As of June 30, 1994, the disposal facility in Barnwell, South Carolina was closed to all LLW disposal for New England nuclear units, forcing all of these units into on-site storage of LLW produced.

Pursuant to the Low-Level Radioactive Waste Policy Act of 1980, each state is responsible for providing disposal facilities for LLW generated within the state and is authorized to join with other states into regional compacts to jointly fulfill their responsibilities. The Connecticut Hazardous Waste Management Service (the Service), a state quasi-public corporation, was charged with coordinating the establishment of a facility for disposal of LLW originating in Connecticut. In June 1991, the Service announced that it had selected three potential sites in north-central Connecticut for further study. The Service's announcement provoked intense controversy in the affected municipalities and resulted in legislative action to stop the selection process. On February 1, 1993, the Service presented to the legislature a new site selection plan under which communities are urged to volunteer a site for a facility in return for financial and other incentives. The volunteer process is being continued through 1996. The Service's activities in this regard are funded by assessments on Connecticut's LLW generators. Due to a change in the volunteer process, there was no assessment for the 1994-1995 fiscal year and the state projects no assessment for the 1995-1996 and 1996-1997 fiscal years. The service currently projects that a disposal site will be designated by 2002, although there are admitted inherent uncertainties in this projection.

Additional LLW storage capacity has been or can be constructed or acquired at the Millstone and Connecticut Yankee sites to provide for temporary storage of LLW should that become necessary. Connecticut LLW can be managed by volume reduction, storage or shipment at least through 2000. The Company cannot predict whether and when a 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 Seabrook Unit 1 has been denied access to existing disposal facilities. Therefore, LLW generated by Seabrook Unit 1 is being stored on-site. The Seabrook storage facility currently has capacity to store at least five years' accumulation of waste generated by Seabrook, and the plant operator plans to expand its storage capacity as necessary.

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 to cover expected decommissioning costs. Changes in NRC requirements or technology can increase estimated decommissioning costs, and UI's customers in future years may experience higher electric rates to offset the effects of any insufficient rate recovery in prior years.

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 \$376 million (in 1995 dollars) as the decommissioning cost estimate for Seabrook Unit 1, of which the Company's share would be about \$66 million. This estimate premises the prompt removal and dismantling of the Unit at the end of its estimated 40-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 1994 was \$1.3 million. UI's share of the fund at December 31, 1994 was approximately \$5.2 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. Current decommissioning cost estimates for Millstone Unit 3 and the Connecticut Yankee Unit are \$448 million (in 1995 dollars) and \$357 million (in 1995 dollars), respectively, of which the Company's share would be about \$17 million and \$34 million, respectively. These estimates premise the prompt removal and dismantling of each unit at the end of its estimated 36-year energy producing life. Monthly decommissioning payments, based on these cost estimates, are being made to decommissioning trust funds managed by Northeast Utilities. UI's share of the Millstone Unit 3 decommissioning payments made during 1994 was \$388,000. UI's share of the fund at December 31, 1994 was approximately \$2.4 million. For the Company's 9.5% equity ownership in Connecticut Yankee, decommissioning costs of \$1.3 million were funded by UI during 1994, and UI's share of the fund at December 31, 1994 was \$14.1 million.

(N) PROPERTY TAX SETTLEMENT

In December 1994, the Company and the City of Bridgeport settled a dispute regarding past taxes payable by the Company on its personal property in that city and agreed upon a method of valuation of personal property for tax purposes for future periods.. As a result of the settlement agreement, the Company recognized a non-recurring charge to 1994 earnings of approximately \$2.5 million (\$1.5 million, after-tax).

(O) FAIR VALUE OF FINANCIAL INSTRUMENTS (1)

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

	1994		1993	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(000's)		(000's)	
Cash and temporary cash investments	$ 11,432	$ 11,432	$ 48,171	$ 48,171
Long-term debt (2)(3)	$651,473	$633,551	$768,601	$810,329

(1) Equity investments were not valued because they were not considered to be material.

(2) Excludes the $250,000,000 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, 1994 and 1993, respectively.

(P) QUARTERLY FINANCIAL DATA (UNAUDITED)

Selected quarterly financial data for 1994 and 1993 are set forth below:

Quarter	Operating Revenues (000's)	Operating Income (4) (000's)	Net Income (Loss) (2)(3)(4) (000's)	Earnings (Loss) Per Share of Common Stock (1)(2)(3)(4)
1994				
First	$167,579	$32,626	$11,938	$ .77
Second	153,433	26,632	6,414	.40
Third	184,592	44,762	25,787	1.78
Fourth	151,144	23,372	2,656	.14
1993				
First	$161,936	$31,164	$12,586	$ .82
Second	151,012	29,335	10,374	.66
Third	189,432	41,358	22,756	1.54
Fourth	150,643	12,957	(5,235)	(.45)

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(1) Based on weighted average number of shares outstanding each quarter.

(2) Earnings per share for the fourth quarter of 1993 include an after-tax charge of $7.8 million or $.56 per share associated with the reorganization of the Company.

(3) Net income and earnings per share for the first quarter of 1994 include an after-tax charge of $1.3 million or $.09 per share associated with the cumulative effect of the change in the method of accounting for postemployment benefits. See Note (H), "Pension and Other Benefits".

(4) Operating income, net income and earnings per share for the fourth quarter of 1994 include an after-tax charge of $1.5 million, or $.10 per share, associated with a property tax settlement, and an after-tax credit of $1.6 million, or $.11 per share, to reverse prior period overestimates of distribution losses.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareowners and Directors of
The United Illuminating Company:

We have audited the accompanying consolidated balance sheets of The United Illuminating Company as of December 31, 1994, 1993 and 1992, and related consolidated statements of income, retained earnings and cash flows for the years then ended and the consolidated financial statement schedule (page S-1). These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule 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 consolidated financial position of The United Illuminating Company as of December 31, 1994, 1993 and 1992, and the consolidated results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedule referred to above, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information required to be included therein.

Coopers & Lybrand L.L.P.

Hartford, Connecticut
January 23, 1995

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures.

Not Applicable

PART III

Item 10. Directors and Executive Officers of the Company.

The information appearing under the captions "NOMINEES FOR ELECTION AS DIRECTORS" AND "COMPLIANCE WITH SECTION 16(a) OF THE SECURITIES EXCHANGE ACT OF 1934" in the Company's definitive Proxy Statement, dated March 29, 1995, for the Annual Meeting of the Shareholders to be held on May 17, 1995, which Proxy Statement will be filed with the Securities and Exchange Commission on or about March 29, 1995, is incorporated by reference in partial answer to this item. See also "EXECUTIVE OFFICERS OF THE COMPANY", following Part I, Item 4 herein.

Item 11. Executive Compensation.

The information appearing under the captions "EXECUTIVE COMPENSATION," "STOCK OPTION PLAN," "STOCK OPTION EXERCISES IN 1994 AND YEAR-END OPTION VALUES," "DIVIDEND EQUIVALENT PROGRAM," "RETIREMENT PLANS," "COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION" AND "DIRECTOR COMPENSATION" in the Company's definitive Proxy Statement, dated March 29, 1995, for the Annual Meeting of the Shareholders to be held on May 17, 1995, which Proxy Statement will be filed with the Securities and Exchange Commission on or about March 29, 1995, is incorporated by reference in answer to this item.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

The information appearing under the captions "PRINCIPAL SHAREHOLDERS" and "STOCK OWNERSHIP OF DIRECTORS AND OFFICERS" in the Company's definitive Proxy Statement, dated March 29, 1995 for the Annual Meeting of the Shareholders to be held on May 17, 1995, which Proxy Statement will be filed with the Securities and Exchange Commission on or about March 29, 1995, is incorporated by reference in answer to this item.

Item 13. Certain Relationships and Related Transactions.

The information appearing under the caption "NOMINEES FOR ELECTION AS DIRECTORS" in the Company's definitive Proxy Statement, dated March 29, 1995, for the Annual Meeting of the Shareholders to be held on May 17, 1995, which Proxy Statement will be filed with the Securities and Exchange Commission on or about March 29, 1995, is incorporated by reference in answer to this item.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

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

Financial Statements (see Item 8):

Consolidated statement of income for the years ended December 31, 1994, 1993 and 1992

Consolidated statement of cash flows for the years ended December 31, 1994, 1993 and 1992

Consolidated balance sheet, December 31, 1994, 1993 and 1992

Consolidated statement of retained earnings for the years ended December 31, 1994, 1993 and 1992

Statement of accounting policies

Notes to consolidated financial statements

Report of independent accountants

Financial Statement Schedule (see S-1)

Schedule II - Valuation and qualifying accounts for the years ended December 31, 1994, 1993 and 1992.

Exhibits:

Pursuant to Rule 12b-32 under the Securities Exchange Act of 1934, certain of the following listed exhibits, which are annexed as exhibits to previous statements and reports filed by the Company, are hereby incorporated by reference as exhibits to this report. Such statements and reports are identified by reference numbers as follows:

(1) Filed with Registration Statement No. 2-60849, effective July 24, 1978.

(2) Filed with Quarterly Report (Form 10-Q) for fiscal quarter ended September 30, 1991.

(3) Filed with Quarterly Report (Form 10-Q) for fiscal quarter ended March 31, 1991.

(4) Filed with Registration Statement No. 33-40169, effective August 12, 1991.

(5) Filed with Registration Statement No. 33-35465, effective August 1, 1990.

(6) Filed with Registration Statement No. 2-57275, effective October 19, 1976.

(7) Filed with Annual Report (Form 10-K) for fiscal year ended December 31, 1991.

(8) Filed with Annual Report (Form 10-K) for fiscal year ended December 31, 1992.

(9) Filed with Annual Report (Form 10-K) for fiscal year ended December 31, 1990.

(10) Filed with Registration Statement No. 2-66518, effective February 25, 1980.

(11) Filed with Registration Statement No. 2-49669, effective December 11, 1973.

(12) Filed with Annual Report (Form 10-K) for fiscal year ended December 31, 1993.

(13) Filed with Registration Statement No. 2-54876, effective November 19, 1975.

(14) Filed with Registration Statement No. 2-52657, effective February 6, 1975.

(15) Filed with Quarterly Report (Form 10-Q) for fiscal quarter ended September 30, 1990.

(16) Filed with Quarterly Report (Form 10-Q) for fiscal quarter ended March 31, 1994.

The exhibit number in the statement or report referenced is set forth in the parenthesis following the description of the exhibit. Those of the following exhibits not so identified are filed herewith.

Exhibit Table Item No.	Exhibit No.	Reference No.	Description
(3)	3.1		Copy of Restated Certificate of Incorporation of The United Illuminating Company, dated January 23, 1995.
(3)	3.2a	(1)	Copy of Bylaws of The United Illuminating Company. (Exhibit 2.3)
(3)	3.2b	(2)	Copy of Article II, Section 2, of Bylaws of The United Illuminating Company, as amended March 26, 1990, amending Exhibit 3.2a. (Exhibit 3.23b)
(3)	3.2c	(3)	Copy of Article V, Section 1, of Bylaws of The United Illuminating Company, as amended April 22, 1991, amending Exhibit 3.2a. (Exhibit 3.23c)
(4)	4.1	(4)	Copy of Indenture, dated as of August 1, 1991, from The United Illuminating Company to The Bank of New York, Trustee. (Exhibit 4)
(4) (10)	4.2	(5)	Copy of Participation Agreement, dated as of August 1, 1990, among Financial Leasing Corporation, Meridian Trust Company, The Bank of New York and The United Illuminating Company. (Exhibits 4(a) through 4(h), inclusive, Amendment Nos. 1 and 2).
(10)	10.1	(6)	Copy of Stockholder Agreement, dated as of July 1, 1964, among the various stockholders of Connecticut Yankee Atomic Power Company, including The United Illuminating Company. (Exhibit 5.1-1)
(10)	10.2a	(6)	Copy of Power Contract, dated as of July 1, 1964, between Connecticut Yankee Atomic Power Company and The United Illuminating Company. (Exhibit 5.1-2)
(10)	10.2b	(1)	Copy of Supplementary Power Contract, dated as of March 1, 1978, between Connecticut Yankee Atomic Power Company and The United Illuminating Company, supplementing Exhibit 10.2a. (Exhibit 5.1-6)
(10)	10.2c	(7)	Copy of Agreement Amending Supplementary Power Contract, dated August 22, 1980, between Connecticut Yankee Atomic Power Company and The United Illuminating Company, amending Exhibit 10.2b. (Exhibit 10.2b)
(10)	10.2d	(8)	Copy of Second Amendment of the Supplementary Power Contract, dated as of October 15, 1982, between Connecticut Yankee Atomic Power Company and The United Illuminating Company, amending Exhibit 10.2b. (Exhibit 10.2d)
(10)	10.2e	(9)	Copy of Second Supplementary Power Contract, dated as of April 30, 1984, between Connecticut Yankee Atomic Power Company and The United Illuminating Company, supplementing Exhibit 10.2a. (Exhibit 10.2e)
(10)	10.2f	(9)	Copy of Additional Power Contract, dated as of April 30, 1984, between Connecticut Yankee Atomic Power Company and The United Illuminating Company. (Exhibit 10.2f)
(10)	10.3	(6)	Copy of Capital Funds Agreement, dated as of September 1, 1964, between Connecticut Yankee Atomic Power Company and The United Illuminating Company. (Exhibit 5.1-3)
(10)	10.4a	(6)	Copy of Connecticut Yankee Transmission Agreement, dated as of October 1, 1964, among the various stockholders of Connecticut Yankee Atomic Power Company, including The United Illuminating Company. (Exhibit 5.1-4)

Exhibit Table Item No.	Exhibit No.	Reference No.	Description
(10)	10.4b	(10)	Copy of Agreement Amending and Revising Connecticut Yankee Transmission Agreement, dated as of July 1, 1979, amending Exhibit 10.4a. (Exhibit 5.1-7)
(10)	10.5	(1)	Copy of Capital Contributions Agreement, dated October 16, 1967, between The United Illuminating Company and Connecticut Yankee Atomic Power Company. (Exhibit 5.1-5)
(10)	10.6a	(7)	Copy of NEPOOL Power Pool Agreement, dated as of September 1, 1971, as amended to November 1, 1988. (Exhibit 10.6a)
(10)	10.6b	(11)	Copy of Agreement Setting Out Supplemental NEPOOL Understandings, dated as of April 2, 1973. (Exhibit 5.7-10)
(10)	10.6c	(7)	Copy of Amendment to NEPOOL Power Pool Agreement, dated as of March 15, 1989, amending Exhibit 10.6a. (Exhibit 10.6c)
(10)	10.6d	(7)	Copy of Agreement Amending NEPOOL Power Pool Agreement, dated as of October 1, 1990, amending Exhibit 10.6a. (Exhibit 10.6d)
(10)	10.6e	(12)	Copy of Agreement Amending NEPOOL Power Pool Agreement, dated as of September 15, 1992, amending Exhibit 10.6a. (Exhibit 10.6e)
(10)	10.6f	(12)	Copy of Agreement Amending NEPOOL Power Pool Agreement, dated as of June 1, 1993, amending Exhibit 10.6a. (Exhibit 10.6f)
(10)	10.7a	(7)	Copy of Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, dated May 1, 1973, as amended to February 1, 1990. (Exhibit 10.7a)
(10)	10.7b	(13)	Copy of Transmission Support Agreement, dated as of May 1, 1973, among the Seabrook Companies. (Exhibit 5.9-2)
(10)	10.7c	(2)	Copy of Twenty-third Amendment to Agreement for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units, dated as of November 1, 1990, amending Exhibit 10.7a. (Exhibit 10.8ab)
(10)	10.8a	(10)	Copy of Sharing Agreement - 1979 Connecticut Nuclear Unit, dated as of September 1, 1973, among The Connecticut Light and Power Company, The Hartford Electric Light Company, Western Massachusetts Electric Company, New England Power Company, The United Illuminating Company, Public Service Company of New Hampshire, Central Vermont Public Service Company, Montaup Electric Company and Fitchburg Gas and Electric Light Company, relating to a nuclear fueled generating unit in Connecticut. (Exhibit 5.8-1)
(10)	10.8b	(14)	Copy of Amendment to Sharing Agreement - 1979 Connecticut Nuclear Unit, dated as of August 1, 1974, amending Exhibit 10.8a. (Exhibit 5.9-2)
(10)	10.8c	(6)	Copy of Amendment to Sharing Agreement - 1979 Connecticut Nuclear Unit, dated as of December 15, 1975, amending Exhibit 10.8a. (Exhibit 5.8-4, Post-effective Amendment No. 2)
(10)	10.9a	(1)	Copy of Transmission Line Agreement, dated January 13, 1966, between the Trustees of the Property of The New York, New Haven and Hartford Railroad Company and The United Illuminating Company. (Exhibit 5.4)
(10)	10.9b	(7)	Notice, dated April 24, 1978, of The United Illuminating Company's intention to extend term of Transmission Line Agreement dated January 13, 1966, Exhibit 10.9a. (Exhibit 10.9b)
(10)	10.9c	(7)	Copy of Letter Agreement, dated March 28, 1985, between The United Illuminating Company and National Railroad Passenger Corporation, supplementing and modifying Exhibit 10.9a. (Exhibit 10.9c)

Exhibit Table Item No.	Exhibit No.	Reference No.	Description
(10)	10.10	(8)	Copy of Agreement, effective May 16, 1992, between The United Illuminating Company and Local 470-1, Utility Workers Union of America, AFL-CIO. (Exhibit 10.10)
(10)	10.11	(12)	Copy of Fuel Oil Purchase and Sale Agreement, dated as of October 1, 1993, among Tosco Corporation, The United Illuminating Company and The Connecticut Light and Power Company. (Confidential treatment requested) (Exhibit 10.11)
(10)	10.12	(8)	Copy of Coal Sales Agreement, dated as of August 1, 1992, between Pittston Coal Sales Corp. and The United Illuminating Company. (Confidential treatment requested) (Exhibit 10.13)
(10)	10.13	(2)	Copy of Fossil Fuel Supply Agreement between BLC Corporation and The United Illuminating Company, dated as of July 1, 1991. (Exhibit 10.31)
(10)	10.14		Copy of Revolving Credit Agreement, dated as of December 15, 1994, among The United Illuminating Company, the Banks named therein, and Citibank, N.A., as Agent for the Banks.
(10)	10.15a*	(8)	Copy of Employment Agreement, dated as of January 1, 1988, between The United Illuminating Company and Richard J. Grossi. (Exhibit 10.22a)
(10)	10.15b*	(15)	Copy of Amendment to Employment Agreement, dated as of July 23, 1990, between The United Illuminating Company and Richard J. Grossi, amending Exhibit 10.15a. (Exhibit 10.26a)
(10)	10.16a*	(8)	Copy of Employment Agreement, dated as of January 1, 1988, between The United Illuminating Company and Robert L. Fiscus. (Exhibit 10.23a)
(10)	10.16b*	(15)	Copy of Amendment to Employment Agreement, dated as of July 23, 1990, between The United Illuminating Company and Robert L. Fiscus, amending Exhibit 10.16a. (Exhibit 10.27a)
(10)	10.17a*	(8)	Copy of Employment Agreement, dated as of January 1, 1988, between The United Illuminating Company and James F. Crowe. (Exhibit 10.24a)
(10)	10.17b*	(15)	Copy of Amendment to Employment Agreement, dated as of July 23, 1990, between The United Illuminating Company and James F. Crowe, amending Exhibit 10.17a. (Exhibit 10.28a)
(10)	10.18*	(7)	Copy of Executive Incentive Compensation Program of The United Illuminating Company. (Exhibit 10.24)
(10)	10.19a*	(15)	Copy of The United Illuminating Company 1990 Stock Option Plan. (Exhibit 10.33)
(10)	10.19b*	(12)	Amendments to The United Illuminating Company 1990 Stock Option Plan, adopted November 22, 1993 and January 24, 1994. (Exhibit 10.21b)
(10)	10.20*	(16)	Copy of The United Illuminating Company Dividend Equivalent Program. (Exhibit 10.20)
(21)	21		List of subsidiaries of The United Illuminating Company.
(27)	27		Financial Data Schedule
(28)	28.1	(8)	Copies of significant rate schedules of The United Illuminating Company. (Exhibit 28.1)

*Management contract or compensatory plan or arrangement.

The foregoing list of exhibits does not include instruments defining the rights of the holders of certain long-term debt of the Company and its subsidiaries where the total amount of securities authorized to be issued under the instrument does not exceed ten (10%) of the total assets of the Company and its subsidiaries on a consolidated basis; and the Company hereby agrees to furnish a copy of each such instrument to the Securities and Exchange Commission on request.

(b) Reports on Form 8-K.

Items Reported	Financial Statements Filed	Date of Report
5, 7	None	September 29, 1994

CONSENT OF INDEPENDENT ACCOUNTANTS

We consent to the incorporation by reference in the Post Effective Amendment No. 1 to the Registration Statement of The United Illuminating Company on Form S-3 (File No. 33-50221) and the Registration Statements on Form S-3 (File No. 33-50445 and File No. 33-55461), of our report, dated January 23, 1995, on our audits of the consolidated financial statements and financial statement schedule of The United Illuminating Company as of December 31, 1994, 1993 and 1992 and for the years then ended, which report is included in this Annual Report on Form 10-K.

Coopers + Lybrand L.L.P.

Hartford, Connecticut
March 7, 1995

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE UNITED ILLUMINATING COMPANY

By /s/ Richard J. Grossi
Richard J. Grossi
Chairman of the Board of Directors
and Chief Executive Officer

Date: March 8, 1995

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

Signature	Title	Date
/s/ Richard J. Grossi (Richard J. Grossi) (Principal Executive Officer)	Director, Chairman of the Board of Directors and Chief Executive Officer	March 8, 1995
/s/ Robert L. Fiscus (Robert L. Fiscus) (Principal Financial and Accounting Officer)	Director, President and Chief Financial Officer	March 8, 1995
/s/ John D. Fassett (John D. Fassett)	Director	March 8, 1995
(William S. Warner)	Director	March , 1995
/s/ John F. Croweak (John F. Croweak)	Director	March 8, 1995
/s/ F. Patrick McFadden, Jr. (F. Patrick McFadden, Jr.)	Director	March 8, 1995
/s/ J. Hugh Devlin (J. Hugh Devlin)	Director	March 8, 1995
/s/ Betsy Henley-Cohn (Betsy Henley-Cohn)	Director	March 8, 1995
/s/Frank R. O'Keefe, Jr. (Frank R. O'Keefe, Jr.)	Director	March 8, 1995
/s/ James A. Thomas (James A. Thomas)	Director	March 8, 1995
(David E.A. Carson)	Director	March , 1995
/s/ John L. Lahey (John L. Lahey)	Director	March 8, 1995

THE UNITED ILLUMINATING COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 1994, 1993 and 1992

(Thousands of Dollars)

Col. A		Col. B	Col. C		Col. D	Col. E
			Additions			
Classification		Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
RESERVE DEDUCTION FROM ASSET TO WHICH IT APPLIES:						
Reserve for uncollectible accounts:						
	1994	$4,700	$9,976	-	$9,776 (A)	$4,900
	1993	3,900	8,971	-	8,171 (A)	4,700
	1992	3,200	8,741	-	8,041 (A)	3,900

NOTE:
(A) Accounts written off, less recoveries.