UNITIL CORP
Form 10-Q
July 28, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

QUARTERLY REPORT UNDER SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For Quarter Ended June 30, 2006

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

New Hampshire	**02-0381573**
(State or other jurisdiction of	***(I.R.S. Employer***
incorporation or organization)	***Identification No.)***
6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive office)	***(Zip Code)***

Registrant s telephone number, including area code: (603) 772-0775

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 whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No x

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

Class	**Outstanding at July 27, 2006**
Common Stock, No par value	5,631,792 Shares

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

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PART I. FINANCIAL INFORMATION

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

SAFE HARBOR CAUTIONARY STATEMENT

This report and the documents we incorporate by reference into this report contain statements that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, included or incorporated by reference into this report, including, without limitation, statements regarding the financial position, business strategy and other plans and objectives for the Unitil Corporation and subsidiaries (Unitil or the Company) future operations, are forward-looking statements.

These statements include declarations regarding Management s beliefs and current expectations. In some cases, forward-looking statements can be identified by terminology such as may, will, should, expects, plans, anticipates, believes, estimates, predicts, potential or negative of such terms or other comparable terminology. These forward-looking statements are subject to inherent risks and uncertainties in predicting future results and conditions that could cause the actual results to differ materially from those projected in these forward-looking statements. Some, but not all, of the risks and uncertainties include the following:

- Variations in weather;
- Changes in the regulatory environment;
- Customers preferences on energy sources;
- Interest rate fluctuation and credit market concerns;
- General economic conditions;
- Increased competition; and
- Fluctuations in supply, demand, transmission capacity and prices for energy commodities.

Many of these risks are beyond the Company s control. Any forward-looking statements speak only as of the date of this report, and the Company undertakes no obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for the Company to predict all of these factors, nor can the Company assess the impact of any such factor on its business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

RESULTS OF OPERATIONS

Earnings Overview

The Company s Earnings Applicable to Common Shareholders (Net Income) was $1.4 million for the second quarter of 2006, a decrease of $0.1 million compared to the same period in 2005. Earnings per common share were $0.25 for the second quarter of 2006, a decrease of $0.02 per share compared with earnings of $0.27 per share for the second quarter of 2005. Earnings for the second quarter of 2006 reflect higher interest and net operating expenses and lower gas sales margins, partially offset by improved margins on electric sales due to the recognition, in the second quarter of 2006, of estimated rate relief for the Company s New Hampshire utility subsidiary.

For the six month period ended June 30, 2006, net income was $3.4 million compared to $4.2 million in the first six months of 2005. Through the first six months, earnings per share were $0.61 for 2006 compared with $0.75 per share for 2005, reflecting higher net operating expenses and interest expense and lower electric and gas sales margins in 2006.

Total electric sales in the three and six months ended June 30, 2006 were down 0.3% and 0.8%, respectively, in the Company s utility service territories. Sales to residential customers increased 0.8% in the three month period

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ended June 30, 2006 compared to the prior year but decreased 0.7% overall in the six month period compared to the prior year primarily due to a significantly milder winter heating season in 2006. Sales to commercial and industrial (C&I) customers decreased 1.0% and 0.9% in the three and six month periods, respectively, compared to the prior year periods due to lower consumption for heating and production purposes.

The Company s New Hampshire utility operating subsidiary, Unitil Energy Systems, Inc. (UES) filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission (NHPUC) which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006. The estimate includes $1.7 million in estimated revenue and $1.0 million in estimated operating expenses and taxes, a net increase to operating income of $0.7 million.

Electric sales margin increased $0.5 million in the three month period ended June 30, 2006 compared to the same period in 2005. For the six month period ended June 30, 2006, electric sales margin decreased $0.3 million compared to the same period in 2005. The lower electric margin for the six months ended June 30, 2006 reflects decreases of $1.8 million related to lower Seabrook Amortization Surcharge (SAS) and other revenues and $0.2 million related to lower sales volume offset by the recognition of $1.7 million of revenue based on the Company s pending rate filing in New Hampshire, discussed above. This decrease in SAS revenues reflects the expiration in the fourth quarter of 2005 of the SAS tariff on Regulatory Assets, which is largely matched by a decrease in amortization expenses on Regulatory Assets (see discussion of Depreciation & Amortization below).

Total sales of natural gas increased 28.9% in the three months ended June 30, 2006 compared to the same period in 2005 and increased 7.7% in the six months ended June 30, 2006 compared to the same period in 2005. The increases in both of these periods were due to a new contract with a large industrial customer. Absent the sales from this new contract, sales to C&I customers were approximately 9.1% and 11.7% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Gas sales to residential customers were 13.0% and 11.5% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The declines in residential and C&I sales reflect lower average energy usage by customers during a period of higher energy prices and significantly milder winter weather in 2006. The weather in the Company s service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, and the country as a whole experienced a record warm January.

Gas sales margin decreased $0.3 million and $0.9 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The decreases in gas margin are attributable to lower sales volume on C&I and residential sales, as discussed above. The Massachusetts Department of Telecommunications and Energy (MDTE) is in the process of approving the margin earned by the Company under the new contract, discussed above. Accordingly, pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin.

Total O&M expense increased $1.0 million and $1.1 million, respectively, in the three and six month periods ended June 30, 2006, compared to the same periods in 2005. On a year to date basis through June 30, 2006, the increase reflects higher retiree and employee benefit costs of $0.9 million, higher salaries and compensation expenses of $0.4 million and higher utility operating costs of $0.1 million, partially offset by lower audit and legal fees of $0.2 million and all other expenses, net of $0.1 million compared to 2005.

Depreciation and Amortization expense decreased $0.6 million and $1.5 million for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These decreases were primarily due to lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company s regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Interest Expense, Net increased by $0.2 million and $0.4 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The change in Interest Expense, Net was primarily driven by a higher weighted average cost of debt in 2006 compared to 2005.

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Operating Revenues Electric

Electric Operating Revenues Total Electric Operating Revenues, increased by $7.3 million, or 15.8%, and by $17.0 million, or 18.3%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Total Electric Operating Revenues include the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in Operating Expenses. The net increase in Total Electric Operating Revenues in the three month period reflects higher Purchased Electricity costs of $6.8 million and higher sales margin of $0.5 million. The net increase in Total Electric Operating Revenues in the six month period reflects higher Purchased Electricity costs of $17.4 million, offset by lower sales margin of $0.3 million and lower C&LM revenues of $0.1 million. As discussed above, the Company has recognized $1.7 million of revenues in the six months ended June 30, 2006 based on the temporary rate order, effective January 1, 2006.

Purchased Electricity and C&LM revenues increased a net $6.8 million, or 14.8%, and $17.4 million, or 18.8%, of Total Electric Operating Revenues in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices and lower spending on energy efficiency programs that were implemented during those periods. Purchased Electricity revenues include the recovery of the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Electricity and C&LM in its rates at cost on a pass through basis.

Electric sales margin (Total Electric Operating Revenues less Cost of Electric Sales) was $14.4 million and $27.3 million in the three and six month periods ended June 30, 2006, respectively. This represents an increase of $0.5 million in the three month period and a decrease of $0.3 million in the six month period, compared to the same periods in 2005. The lower sales margin for the six months ended June 30, 2006, reflects decreases of $1.8 million related to lower SAS and other revenues and $0.2 million related to lower sales volume offset by the recognition of $1.7 million of revenue based on the Company s pending rate filing in New Hampshire, discussed above. The decrease in SAS revenues reflects the expiration in the fourth quarter of 2005 of the SAS tariff on Regulatory Assets, which is largely matched by a decrease in amortization expenses on Regulatory Assets (see discussion of Depreciation & Amortization below).

The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2006 and 2005:

Electric Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**$ Change**	**% Change[1]**	**2006**	**2005**	**$ Change**	**% Change[1]**
Electric Operating Revenue:								
Residential	**$ 23.3**	$ 18.5	$ 4.8	10.4%	**$ 47.6**	$ 39.5	$ 8.1	8.7%
Commercial / Industrial	**30.0**	27.5	2.5	5.4%	**62.2**	53.3	8.9	9.6%
Total Electric Operating Revenue	**$ 53.3**	$ 46.0	$ 7.3	15.8%	**$ 109.8**	$ 92.8	$ 17.0	18.3%
Cost of Electric Sales:								
Purchased Electricity	**$ 37.8**	$ 31.0	$ 6.8	14.8%	**$ 80.7**	$ 63.3	$ 17.4	18.8%
Conservation & Load Management	**1.1**	1.1			**1.8**	1.9	(0.1)	(0.1%)
Electric Sales Margin	**$ 14.4**	$ 13.9	$ 0.5	1.0%	**$ 27.3**	$ 27.6	$ (0.3)	(0.4%)

[1] Represents change as a percent of Total Electric Operating Revenue.

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Kilowatt-hour Sales - Unitil s total electric kWh sales were 0.3% and 0.8% lower in the three and six months ended June 30, 2006, respectively, compared with the same periods in 2005, reflecting customer growth offset by milder weather and a decline in average energy usage as customers appear to be reacting to higher energy prices by better managing their energy consumption. The weather in the Company s service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, resulting in lower consumption of electricity for heating. In the second quarter of 2006 the weather in the Company s service territories was approximately 54% cooler than in the same period for 2005, resulting in lower consumption of electricity for cooling. Sales to residential customers increased 0.8% in the three month period as compared to the prior year period and decreased 0.7% in the six month period as compared to the prior year period. Sales to commercial and industrial (C&I) customers decreased 1.0% and 0.9% in the three and six month periods, respectively, as compared to the prior year periods.

The following table details total kWh sales for the three and six months ended June 30, 2006 and 2005 by major customer class:

kWh Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**Change**	**% Change**	**2006**	**2005**	**Change**	**% Change**
Residential	**149.7**	148.5	1.2	0.8%	**332.9**	335.3	(2.4)	(0.7%)
Commercial / Industrial	**262.8**	265.4	(2.6)	(1.0%)	**530.6**	535.4	(4.8)	(0.9%)
Total	**412.5**	413.9	(1.4)	(0.3%)	**863.5**	870.7	(7.2)	(0.8%)

Operating Revenues - Gas

Gas Operating Revenues Total Gas Operating Revenues increased $1.3 million, or 26.0%, and $2.4 million, or 13.7%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Total Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses. The net increase in Total Gas Operating Revenues in the three month period reflects higher Purchased Gas costs of $1.6 million, partially offset by lower sales margin of $0.3 million. The net increase in Total Gas Operating Revenues in the six month period reflects higher Purchased Gas costs of $3.3 million, offset by lower sales margin of $0.9 million.

Purchased Gas and C&LM revenues increased a net $1.6 million, or 32.0%, and $3.3 million, or 18.8%, of Total Gas Operating Revenues in the three and six month periods ended June 30, 2006, respectively, compared to the same period in 2005, reflecting higher gas commodity prices, higher unit sales and relatively flat spending on energy efficiency programs that were implemented during those periods. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. C&LM revenues include the recovery of the cost of energy efficiency and conservation programs. The Company recovers the cost of Purchased Gas and C&LM in its rates at cost on a pass through basis.

Gas sales margin (Total Gas Operating Revenue less the Cost of Gas Sales) was $1.8 million and $5.2 million in the three and six month periods ended June 30, 2006, respectively. This represents decreases of $0.3 million, or 6.0%, and $0.9 million, or 5.1%, of Total Gas Operating Revenue in the three and six month periods compared to the same periods in 2005, respectively.

For the three month period, approximately $0.2 million of the decrease in gas sales margin is due to lower gas sales. Overall, gas sales were 28.9% higher in the second quarter of 2006 than in the same period of 2005, but this increase in gas sales is due to a new contract with a large industrial customer. Absent the sales from this new contract, gas sales were approximately 11.1% lower for the three month period ended June 30, 2006, compared to the same period in 2005. The Massachusetts Department of Telecommunications and Energy (MDTE) is in the process of approving the margin earned by the Company under the new contract, discussed above. Pending the results of this proceeding, the Company is recording revenue from this contract on a reduced basis and therefore the significant increase in gas sales due to this contract is not matched by a similar increase in sales margin. The remainder of the decrease in gas sales margin in the three month period is due to changes in the mix of customer billings period over period.

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For the six month period, approximately $0.7 million of the decrease in gas sales margin is due to lower gas sales. Gas sales were 7.7% higher in the six months ended June 30, 2006 than in the same period of 2005. This increase in sales is due to the new transportation contract with a large industrial customer discussed above. Absent the sales from this new contract, gas sales were approximately 11.6% lower for the six months ended June 30, 2006 compared to the same period in 2005. The remainder of the decrease in gas sales margin in the six month period is due to changes in the mix of customer billings period over period.

The following table details total Gas Operating Revenues and Sales Margin for the three and six months ended June 30, 2006 and 2005:

Gas Operating Revenues and Sales Margin (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**$ Change**	**% Change[(1)]**	**2006**	**2005**	**$ Change**	**% Change[(1)]**
Gas Operating Revenue:								
Residential	**$ 3.2**	$ 3.0	$ 0.2	4.0%	**$ 11.0**	$ 10.5	$ 0.5	2.8%
Commercial / Industrial	**2.1**	1.8	0.3	6.0%	**7.8**	7.0	0.8	4.6%
Total Firm Gas Revenue	**$ 5.3**	$ 4.8	$ 0.5	10.0%	**$ 18.8**	$ 17.5	$ 1.3	7.4%
Interruptible Gas Revenue	**1.0**	0.2	0.8	16.0%	**1.2**	0.1	1.1	6.3%
Total Gas Operating Revenue	**$ 6.3**	$ 5.0	$ 1.3	26.0%	**$ 20.0**	$ 17.6	$ 2.4	13.7%
Cost of Gas Sales:								
Purchased Gas	**$ 4.4**	$ 2.8	$ 1.6	32.0%	**$ 14.6**	$ 11.3	$ 3.3	18.8%
Conservation & Load Management	**0.1**	0.1			**0.2**	0.2		
Gas Sales Margin	**$ 1.8**	$ 2.1	$ (0.3)	(6.0%)	**$ 5.2**	$ 6.1	$ (0.9)	(5.1%)

(1) Represents change as a percent of Total Gas Operating Revenue.

Therm Sales Unitil s total gas sales increased 28.9% in the three months ended June 30, 2006 compared to the same period in 2005 and increased 7.7% in the six months ended June 30, 2006 compared to the same period in 2005. The increases in both of these periods were due to a new gas sales contract with a large industrial customer. Absent the sales from this new contract, sales to C&I customers were approximately 9.1% and 11.7% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Gas sales to residential customers were 13.0% and 11.5% lower for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The declines in residential and C&I sales reflect lower average energy usage by customers during a period of higher energy prices and significantly milder winter weather in 2006. The weather in the Company s service territories in the first quarter of 2006 was approximately 12% warmer than in the same period for 2005, and the country as a whole experienced a record warm January.

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The following table details total firm therm sales for the three and six months ended June 30, 2006 and 2005, by major customer class:

Therm Sales (millions)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**Change**	**% Change**	**2006**	**2005**	**Change**	**% Change**
Residential	**2.0**	2.3	(0.3)	(13.0%)	**6.9**	7.8	(0.9)	(11.5%)
Commercial / Industrial	**3.8**	2.2	1.6	72.7%	**9.8**	7.7	2.1	27.3%
Total	**5.8**	4.5	1.3	28.9%	**16.7**	15.5	1.2	7.7%

Operating Revenue - Other

Total Other Revenue increased $0.2 million, or 35.4%, and $0.2 million, or 25.8% in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These increases were the result of growth in revenues from the Company s unregulated energy brokering business, Usource.

The following table details total Other Revenue for the three and six months ended June 30, 2006 and 2005:

Other Revenue (000 s)

	Three Months Ended June 30,				Six Months Ended June 30,			
	2006	**2005**	**$ Change**	**% Change**	**2006**	**2005**	**$ Change**	**% Change**
Other	**$ 612**	$ 452	160	35.4%	**$ 1,199**	$ 953	$ 246	25.8%
Total Other Revenue	**$ 612**	$ 452	$ 160	35.4%	**$ 1,199**	$ 953	$ 246	25.8%

Operating Expenses

Purchased Electricity Purchased Electricity expenses include the cost of electric supply as well as other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $6.8 million, or 22.0%, and $17.4 million, or 27.5%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005, reflecting higher electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Purchased Gas Purchased Gas expenses include the cost of gas purchased and manufactured to supply the Company s total gas supply requirements. Purchased Gas increased $1.5 million, or 54.2%, and $3.3 million, or 29.3%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These increases in Purchased Gas are attributable to increased therm sales and higher gas commodity costs. The Company recovers the costs of Purchased Gas in its rates at cost on a pass through basis and therefore changes in these expenses do not affect Net Income.

Operation and Maintenance (O&M) - O&M expense includes electric and gas utility operating costs, and the operating cost of the Company s unregulated business activities. Total O&M expense increased $1.0 million and $1.1 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. For the six month period, the increase reflects higher retiree and employee benefit costs of $0.9 million, higher salaries and compensation expenses of $0.4 million and higher utility operating costs of $0.1 million, partially offset by lower audit and legal fees of $0.2 million and all other expenses, net of $0.1 million.

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Conservation & Load Management C&LM expenses are associated with the development, management, and delivery of the Company s Energy Efficiency programs. Energy Efficiency programs are designed, in conformity with state regulatory requirements, to help consumers use natural gas and electricity more efficiently and thereby decrease their energy costs. Programs are tailored to residential, small business and large business customer groups and provide educational materials, technical assistance, and rebates that contribute toward the cost of purchasing and installing approved measures. Approximately 90% of these costs are related to electric operations and 10% to gas operations.

Total C&LM expenses decreased less than $0.1 million, or 0.7%, and $0.1 million, or 4.0%, in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The decreases reflect the timing of spending on the implementation of Energy Efficiency programs. These costs are collected from customers on a pass through basis and therefore, fluctuations in program costs have no impact on Net Income.

Depreciation, Amortization and Taxes

Depreciation and Amortization - Depreciation and Amortization expense decreased $0.6 million, or 11.7% and $1.5 million, or 14.6%, for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. These decreases were due to lower amortization on regulatory assets, partially offset by depreciation on normal utility plant additions. The Company s regulatory asset related to its former abandoned property investment in Seabrook Station became fully-amortized in the third quarter of 2005.

Local Property and Other Taxes - Local Property and Other Taxes increased by $0.1 million, or 5.9%, and $0.1 million, or 3.2%, for the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. The increase in the three month period was due to higher local property tax rates and higher payroll taxes. The increase in the six month period was due to higher payroll taxes.

Federal and State Income Taxes - Federal and State Income Taxes were lower by $0.1 million and $0.4 million in the three and six months ended June 30, 2006, respectively, compared to the same periods in 2005 reflecting lower pre-tax earnings.

Interest Expense, Net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and short-term borrowings. Certain reconciling rate mechanisms used by the Company s distribution operating utilities give rise to regulatory assets (and regulatory liabilities) on which interest is calculated.

The Company operates a number of reconciling rate mechanisms to recover specifically identified costs on a pass through basis. These reconciling rate mechanisms track costs and revenue on a monthly basis. In any given month, this monthly tracking and reconciling process will produce either an under-collected or an over-collected balance of costs. In accordance with the Company s tariff, interest is accrued on these balances and will produce either interest income or interest expense. Interest income is recorded on an under-collection of costs, which creates a regulatory asset to be recovered in future periods when rates are reset. Interest expense is recorded on an over-collection of costs, which creates a regulatory liability to be refunded in future periods when rates are reset.

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Interest Expense, Net (000 s)	Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
Interest Expense				
Long-term Debt	**$ 2,303**	$ 2,100	**$ 4,622**	$ 4,202
Short-term Debt	**411**	225	**716**	441
Regulatory Liabilities	**67**	63	**109**	102
Subtotal Interest Expense	**2,781**	2,388	**5,447**	4,745
Interest Income				
Regulatory Assets	**(759)**	(637)	**(1,486)**	(1,225)
AFUDC and Other	**(56)**	(19)	**(82)**	(33)
Subtotal Interest Income	**(815)**	(656)	**(1,568)**	(1,258)
Total Interest Expense, Net	**$ 1,966**	$ 1,732	**$ 3,879**	$ 3,487

Interest Expense, Net increased by $0.2 million and $0.4 million in the three and six month periods ended June 30, 2006, respectively, compared to the same periods in 2005. Interest expense on long-term borrowings increased in both the three and six month periods in 2006 compared to 2005 due to the issuance of fixed rate long-term debt. In December 2005 Unitil s Massachusetts utility subsidiary, FG&E issued $15 million of unsecured long-term notes to institutional investors. Interest expense on short-term debt increased in both the three and six month periods in 2006 compared to 2005 primarily due to higher average short-term interest rates. These increases in interest expense were partially offset by an increase in interest income on regulatory assets primarily due to higher carrying charges on regulatory assets.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $11.0 million during the first six months of 2006, a decrease of $2.8 million over the comparable period in 2005. Net Income was $0.8 million lower in the first half of 2006 compared to 2005. Depreciation and Amortization declined by $1.5 million in the six months ended June 30, 2006 as compared to the same period in 2005 reflecting a lower amortization on regulatory assets. The Deferred Tax Provision increased by $1.7 million during the first half of 2006 compared to the same period in 2005, reflecting a net change between current and deferred income taxes related to changes in Accrued Revenue balances. Cash sources from Accrued Revenue decreased by $3.9 million period over period due to higher energy costs, which will be collected from customers in future periods. Taxes Payable declined by $2.3 million, reflecting higher tax payments in 2006 compared to 2005. Cash uses for Accounts Payable decreased by $1.5 million compared to last year reflecting a higher level of funding of energy obligations in 2005. In addition, uses of cash for Deferred Restructuring Costs declined by $2.3 million in the first six months of 2006 compared to the same period last year. Deferred Restructuring Costs are regulatory assets that will be recovered from customers in future periods. All other changes in cash flows from operating activities were a net increase of $0.2 million in cash provided by operating activities.

Cash used in investing activities was $14.4 million for the six months ended June 30, 2006 an increase of $4.9 million over the comparable period in 2005. Annual capital expenditures are presently budgeted to be $33.4 million in 2006 compared to $24.4 million expended in 2005. These 2006 capital expenditures include approximately $6.6 million of cash outlays for the Automated Metering Infrastructure projects, which are expected to be completed in May 2007. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows provided by financing activities were $4.1 million in the first six months of 2006. In the comparable period of 2005 cash used in financing activities amounted to $4.0 million, a net change between the two periods of $8.1 million. Cash provided for financing activities in the current period includes the proceeds from short-term bank borrowings of $8.0 million compared to the repayment of $0.2 million of short-term bank borrowings during the same period in 2005. The current period reflects the early repurchase of $0.2 million of preferred stock. Both periods reflect the payment of dividends to shareholders of approximately $3.9 million. During the first six months

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of 2006 and 2005, normal sinking fund payments amounted to approximately $0.2 million during both periods. Both periods include the proceeds of approximately $0.5 million received from the sale of Unitil Common Stock through the Dividend Reinvestment and Stock Purchase Plan and 401(k) plans. During the first half of 2005 the Company repaid capital lease obligations of $0.2 million.

Unitil s subsidiary, UES expects to conclude a $15 million First Mortgage Bond issuance on or about September 30, 2006. This transaction is subject to the approval of the NHPUC and the final approval of UES Board of Directors. The proceeds from this financing will be used principally to reduce short-term debt, and for other corporate purposes. Accordingly, as discussed below, the Company reduced its unsecured credit lines by $4.0 million as of June 30, 2006.

At June 30, 2006, Unitil had completed the successful renewal of $40.0 million in unsecured revolving lines of credit through three banks. This represents a reduction from previously unsecured credit lines of $4.0 million. Average daily short-term borrowings during the first six months of 2006 were approximately $25.0 million, an increase of approximately $0.8 million over the comparable period in 2005. At June 30, 2006, the Company had available approximately $13.3 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $26.7 million. In addition, Unitil had $3.9 million in cash at June 30, 2006.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company s policy is to limit these guarantees to two years or less. As of June 30, 2006, there are $8.0 million of guarantees outstanding and the longest term guarantee extends through May 31, 2008.

Critical Accounting Policies

The preparation of the Company s financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In making those estimates and assumptions, management is sometimes required to make difficult, subjective and/or complex judgments about the impact of matters that are inherently uncertain and for which different estimates that could reasonably have been used could have resulted in material differences in its financial statements. If actual results were to differ significantly from those estimates, assumptions and judgments, the financial statements of the Company could be materially different than reported. The following is a summary of the Company s most critical accounting policies, which are defined as those policies where judgments or uncertainties could materially affect the application of those policies. For a complete discussion of the Company s significant accounting policies, refer to the Note 1 to the Consolidated Financial Statements in the Company s Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 22, 2006.

Regulatory Accounting - The Company s principal business is the distribution of electricity and natural gas by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, Accounting for the Effects of Certain Types of Regulation. (SFAS No. 71). In accordance with SFAS No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered or refunded in future electric and gas retail rates.

SFAS No. 71 specifies the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and how these effects are to be accounted for by a regulated enterprise. Revenues intended to cover some costs may be recorded either before or after the costs are incurred. If regulation provides assurance that incurred costs will be recovered in the future, these costs would be recorded as deferred charges or regulatory assets under SFAS No. 71. If revenues are recorded for costs that are expected to be incurred in the future, these revenues would be recorded as deferred credits or regulatory liabilities under SFAS No. 71.

The Company s principal regulatory assets and liabilities are detailed on the Company s Consolidated Balance Sheet. The Company is currently receiving or being credited with a return on all of its regulatory assets for which

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a cash outflow has been made. The Company is currently paying or being charged with a return on all of its regulatory liabilities for which a cash inflow has been received. The Company s regulatory assets and liabilities will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company s consolidated financial statements. Management believes it is probable that the Company s regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of FASB Statement No. 101, Regulated Enterprises Accounting for the Discontinuation of Application of Financial Accounting Standards Board Statement No. 71. In management s opinion, the Company s regulated operations will be subject to SFAS No. 71 for the foreseeable future.

Utility Revenue Recognition - Regulated utility revenues are based on rates approved by state and federal regulatory commissions. These regulated rates are applied to customers accounts based on their actual or estimated use of energy. Energy sales to customers are based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

As discussed above, the Company s New Hampshire utility operating subsidiary, UES, filed a request for a base rate increase of $4.65 million with the New Hampshire Public Utilities Commission (NHPUC) which established temporary rate relief at current rate levels, effective January 1, 2006. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The rate filing is currently under review, with a NHPUC order anticipated before the end of 2006. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company s experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when state regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations - The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in

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accordance with FASB Statement No. 87, Employers Accounting for Pensions (SFAS No. 87) and FASB Statement No. 106, Employers Accounting for Postretirement Benefits other than Pensions (SFAS No. 106). In applying these accounting policies, the Company has made critical estimates related to actuarial assumptions, including assumptions of expected returns on plan assets, future compensation, health care cost trends, and appropriate discount rates. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit cost is based on several significant assumptions.

The Company s reported costs of providing pension and PBOP benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. The Company s health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. Pension and PBOP costs (collectively postretirement costs) are affected by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also affect current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. If these assumptions were changed, the resultant change in benefit obligations, fair values of plan assets, funded status and net periodic benefit costs could have a material impact on the Company s consolidated financial statements. See Note 8.

Pension expense is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries and investment managers. The Company s expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in common stock equities and 40% in fixed income securities. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

Income Taxes - Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company s actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under FASB Statement No. 109, Accounting for Income Taxes. The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation - Depreciation expense is calculated based on the useful lives of assets and judgment is involved when estimating the useful lives of certain assets. A change in the estimated useful lives of these assets could have a material impact on the Company s consolidated financial statements. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company s fixed assets.

Commitments and Contingencies - The Company s accounting policy is to record and/or disclose commitments and contingencies in accordance with FASB Statement No. 5, Accounting for Contingencies (SFAS No. 5). SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss that will ultimately be resolved when one or more future events occur or fail to occur.

Refer to Recently Issued Accounting Pronouncements in Note 1 of the Notes of Consolidated Financial Statements for information regarding recently issued accounting standards.

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LABOR RELATIONS

There are approximately 100 employees of the Company represented by labor unions. In May 2005, the Company reached agreements with its bargaining units for new five-year contracts, effective June 1, 2005. These agreements replace contracts that expired on May 31, 2005.

INTEREST RATE RISK

The majority of the Company s debt outstanding represents long-term notes bearing fixed rates of interest. Changes in market interest rates do not affect interest expense resulting from these outstanding long-term debt securities. However, the Company periodically repays its short-term debt borrowings through the issuance of new long-term debt securities. Changes in market interest rates may affect the interest rate and corresponding interest expense on any new long-term debt securities issued by the Company. In addition, the Company s short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease the Company s interest expense in future periods. For example, if the Company had an average amount of short-term debt outstanding of $25 million for the period of one year, a change in interest rates of 1% would result in a change in annual interest expense of approximately $250,000 (pre-tax). The average interest rates on the Company s short-term borrowings for the three months ended June 30, 2006 and June 30, 2005 were 5.46% and 3.51%, respectively. The average interest rates on the Company s short-term borrowings for the six months ended June 30, 2006 and June 30, 2005 were 5.24% and 3.27%, respectively.

MARKET RISK

Although Unitil s utility operating companies were subject to commodity price risk as part of their traditional operations, the current regulatory framework within which these companies operate allows for full collection of power and gas costs in rates on a pass-through basis. Consequently, there is limited commodity price risk after consideration of the related rate-making which involves the pre-approval of the commodity prices included in rates. Additionally, as discussed below in Regulatory Matters, the Company has divested its long-term commodity-related contracts and therefore, has further reduced its exposure to commodity risk. In recent periods, the energy markets have experienced significant volatility, with unprecedented increases in energy prices. The Company is working with the regulatory commissions to address the issue of increasing energy prices and help the Company s customers work through this difficult period. The regulatory commissions in Massachusetts and New Hampshire have continued to approve full collection of these costs by Unitil s utility operating companies. However, the risk exists that the regulatory commissions would require the Company to finance, through deferrals, a portion of these costs for a period of time.

REGULATORY MATTERS

Please refer to Note 6 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Regulatory Matters.

ENVIRONMENTAL MATTERS

Please refer to Note 7 to the Consolidated Financial Statements in Part I, Item 1 of this report for a discussion of Environmental Matters.

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Item 1. Financial Statements

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF EARNINGS

(000 s except common shares and per share data)

(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Operating Revenues				
Electric	**$ 53,328**	$ 46,034	**$ 109,758**	$ 92,846
Gas	**6,286**	4,953	**19,972**	17,640
Other	**612**	452	**1,199**	953
Total Operating Revenues	**60,226**	51,439	**130,929**	111,439
Operating Expenses				
Purchased Electricity	**37,781**	30,956	**80,693**	63,282
Purchased Gas	**4,378**	2,839	**14,564**	11,263
Operation and Maintenance	**7,061**	6,097	**13,153**	12,015
Conservation & Load Management	**1,190**	1,198	**1,987**	2,069
Depreciation and Amortization	**4,341**	4,915	**8,520**	9,981
Provisions for Taxes:				
Local Property and Other	**1,407**	1,328	**2,904**	2,814
Federal and State Income	**739**	795	**1,844**	2,200
Total Operating Expenses	**56,897**	48,128	**123,665**	103,624
Operating Income	**3,329**	3,311	**7,264**	7,815
Non-Operating Expenses (Income)	**(72)**	43	**(93)**	82
Income Before Interest Expense	**3,401**	3,268	**7,357**	7,733
Interest Expense, Net	**1,966**	1,732	**3,879**	3,487
Net Income	**1,435**	1,536	**3,478**	4,246
Less: Dividends on Preferred Stock	**34**	39	**64**	78
Earnings Applicable to Common Shareholders	**$ 1,401**	$ 1,497	**$ 3,414**	$ 4,168
Average Common Shares Outstanding - Basic	**5,592,616**	5,547,269	**5,584,935**	5,540,196
Average Common Shares Outstanding - Diluted	**5,606,609**	5,563,115	**5,599,108**	5,555,390
Earnings Per Common Share (Basic and Diluted)	**$ 0.25**	$ 0.27	**$ 0.61**	$ 0.75
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(000 s)

	(UNAUDITED) June 30, 2006	(UNAUDITED) June 30, 2005	December 31, 2005
ASSETS:			
Utility Plant:			
Electric	**$ 239,994**	$ 230,201	$ 234,153
Gas	**59,491**	54,237	58,675
Common	**25,826**	27,259	26,515
Construction Work in Progress	**11,735**	3,237	5,624
Total Utility Plant	**337,046**	314,934	324,967
Less: Accumulated Depreciation	**116,794**	108,807	111,646
Net Utility Plant	**220,252**	206,127	213,321
Current Assets:			
Cash	**3,854**	3,335	3,207
Accounts Receivable Net of Allowance for Doubtful Accounts of $1,199, $501 and $550	**23,038**	18,050	23,551
Accrued Revenue	**8,706**	6,578	8,905
Refundable Taxes			351
Materials and Supplies	**3,490**	2,957	3,675
Prepayments	**1,901**	2,117	1,612
Total Current Assets	**40,989**	33,037	41,301
Noncurrent Assets:			
Regulatory Assets	**167,627**	186,544	179,719
Prepaid Pension Costs	**9,794**	9,932	11,099
Debt Issuance Costs	**2,343**	2,236	2,343
Other Noncurrent Assets	**3,429**	5,094	2,218
Total Noncurrent Assets	**183,193**	203,806	195,379
TOTAL	**$ 444,434**	$ 442,970	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS (Cont.)

(000 s)

	(UNAUDITED)		
	June 30,		December 31,
	2006	2005	2005
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 94,582**	$ 93,377	$ 96,283
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**1,858**	2,102	2,102
Long-Term Debt, Less Current Portion	**125,199**	110,523	125,365
Total Capitalization	**221,864**	206,227	223,975
Current Liabilities:			
Long-Term Debt, Current Portion	**323**	296	308
Capitalized Leases, Current Portion	**278**	243	261
Accounts Payable	**19,705**	13,894	20,600
Short-Term Debt	**26,650**	25,490	18,700
Dividends Declared and Payable	**1,988**	1,975	50
Refundable Customer Deposits	**2,082**	1,757	2,031
Taxes Payable	**570**	2,284	
Interest Payable	**1,353**	1,328	1,353
Other Current Liabilities	**2,137**	1,982	2,597
Total Current Liabilities	**55,086**	49,249	45,900
Deferred Income Taxes	**50,951**	52,596	52,297
Noncurrent Liabilities:			
Power Supply Contract Obligations	**102,245**	127,677	114,906
Capitalized Leases, Less Current Portion	**323**	109	324
Other Noncurrent Liabilities	**13,965**	7,112	12,599
Total Noncurrent Liabilities	**116,533**	134,898	127,829
TOTAL	**$ 444,434**	$ 442,970	$ 450,001

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(000 s)

(UNAUDITED)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Cash Flow from Operating Activities:		
Net Income	**$ 3,478**	$ 4,246
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**8,520**	9,981
Deferred Taxes	**(964)**	(2,653)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**513**	69
Accrued Revenue	**(743)**	3,176
Taxes Refundable / Payable	**921**	3,261
Materials and Supplies	**185**	123
Prepayments and Other	**(289)**	(346)
Accounts Payable	**(895)**	(2,355)
Refundable Customer Deposits	**51**	212
Other Current Liabilities	**(460)**	616
Deferred Restructuring and Other Charges	**(534)**	(2,805)
Other, net	**1,188**	224
Cash Provided by Operating Activities	**10,971**	13,749
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(14,438)**	(9,498)
Cash (Used in) Investing Activities	**(14,438)**	(9,498)
Cash Flows from Financing Activities:		
Proceeds from (Repayment) of Short-Term Debt, net	**7,950**	(185)
Repayment of Long-Term Debt	**(151)**	(141)
Dividends Paid	**(3,939)**	(3,913)
Issuance of Common Stock	**513**	546
Retirement of Preferred Stock	**(243)**	(11)
Repayment of Capital Lease Obligations	**(16)**	(244)
Cash Provided by (Used in) Financing Activities	**4,114**	(3,948)
Net Increase in Cash	**647**	303
Cash at Beginning of Period	**3,207**	3,032
Cash at End of Period	**$ 3,854**	$ 3,335
Supplemental Cash Flow Information:		
Interest Paid	**$ 5,358**	$ 4,685
Income Taxes Paid	**$ 1,893**	$ 1,693

(The accompanying notes are an integral part of these consolidated unaudited financial statements.)

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation The accompanying unaudited consolidated financial statements of Unitil have been prepared in accordance with the instructions to Form 10-Q and include all of the information and footnotes required by generally accepted accounting principles. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. The results of operations for the three and six months ended June 30, 2006 are not necessarily indicative of results to be expected for the year ending December 31, 2006. For further information, please refer to Note 1 of Part II to the Consolidated Financial Statements Summary of Significant Accounting Policies of the Company s Form 10-K for the year ended December 31, 2005, as filed with the SEC on February 22, 2006, for a description of the Company s Basis of Presentation.

Nature of Operations Unitil Corporation (Unitil or the Company) is a public utility holding company. Unitil and its subsidiaries are subject to regulation as a holding company system by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission (SEC). As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil s former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

Unitil s principal business is the retail distribution of electricity in the southeastern seacoast and capital city areas of New Hampshire and the retail distribution of both electricity and natural gas in the greater Fitchburg area of north central Massachusetts, through the Company s two wholly owned subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities.

A third utility subsidiary, Unitil Power, formerly functioned as the full requirements wholesale power supply provider for UES. In connection with the implementation of electric industry restructuring in New Hampshire, Unitil Power ceased being the wholesale supplier of UES on May 1, 2003 and divested of its long-term power supply contracts through the sale of the entitlements to the electricity associated with various electric power supply contracts it had acquired to serve UES customers.

Unitil also has three other wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and management services on a centralized basis to its affiliated Unitil companies. Unitil Realty owns and manages the Company s corporate office in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. Unitil Resources is the Company s wholly-owned non-utility unregulated subsidiary that provides consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States.

Recently Issued Pronouncements In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarified the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, Accounting for Income Taxes (SFAS No. 109). Specifically, FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise s financial statements. Additionally, FIN 48 provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods of income taxes, as well as the required disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company is in the process of completing its analysis of FIN 48 as it applies to the Company s operations and it does not expect that the adoption of FIN 48 will have a significant impact on the Company s Consolidated Financial Statements.

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In March 2006, the FASB issued a Proposed Statement of Financial Accounting Standards (SFAS), Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. The Proposed SFAS would amend SFAS No. 87, SFAS No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, SFAS No. 106 and SFAS No. 132(R), Employers Disclosures about Pensions and Other Postretirement Benefits. The Proposed SFAS would require companies to record on their balance sheets pension assets and liabilities, based on projected benefit obligations, and transition assets and obligations. Additionally, the Proposed SFAS would require companies to recognize in their statements of earnings actuarial gains and losses and prior service costs and credits which have not yet been recorded as expense. The effective date of the Proposed SFAS is proposed to be December 15, 2006. The Company is currently assessing the impact the Proposed SFAS would have on the Company s results of operations and financial position.

In February 2006, the FASB issued FASB Statement No. 155, Accounting for Certain Hybrid Financial Instruments , (SFAS No. 155), which amends FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities , (SFAS No.133) and FASB Statement No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities , (SFAS No. 140), effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. The Company has adopted SFAS No. 155 and it did not have an impact on the Company s Consolidated Financial Statements.

In February 2006, the FASB issued FASB Staff Position No. FAS 123(R)-4, (FSP 123(R)-4), Classification of Options and Similar Instruments Issued as Employee Compensation That Allow for Cash Settlement Upon the Occurrence of a Contingent Event . FSP 123(R)-4 addresses the classification of options and similar instruments issued as employee compensation that allow for cash settlement upon the occurrence of a contingent event and amends paragraphs 32 and A229 of revised FASB Statement No. 123(R), Share-Based Payment , (SFAS No. 123(R)), which was issued in December 2004. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company uses the fair value method for share-based payment awards and therefore the provisions of SFAS No. 123(R) have no impact on the Consolidated Financial Statements. The Company has adopted the provisions of FSP 123(R)-4.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year presentation.

NOTE 2 DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
06/22/06	08/15/06	08/01/06	$ 0.345
03/23/06	05/15/06	05/01/06	$ 0.345
01/12/06	02/15/06	02/01/06	$ 0.345
09/23/05	11/15/05	11/01/05	$ 0.345
06/17/05	08/15/05	08/01/05	$ 0.345
03/24/05	05/13/05	04/29/05	$ 0.345
01/13/05	02/15/05	02/01/05	$ 0.345

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NOTE 3 COMMON STOCK AND PREFERRED STOCK

During the second quarter of 2006, the Company sold 10,849 shares of its Common Stock, at an average price of $24.68 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $268,000 were used to reduce short-term borrowings.

During the second quarter of 2005, the Company sold 9,274 shares of its Common Stock, at an average price of $26.63 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $247,000 were used to reduce short-term borrowings.

The Company maintains a Restricted Stock Plan (the Plan) which has been ratified and approved by the Company s shareholders. On February 16, 2006, 14,375 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $366,563. On March 8, 2005, 10,900 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $299,423. On April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

Details on preferred stock at June 30, 2006, June 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30,		December 31,
	2006	**2005**	**2005**
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**874**	892	892
8.00% Series, $100 Par Value	**984**	1,210	1,210
Total Preferred Stock	**$ 2,083**	$ 2,327	$ 2,327

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NOTE 4 LONG-TERM DEBT

Details on long-term debt at June 30, 2006, June 30, 2005 and December 31, 2005 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30, 2006	June 30, 2005	December 31, 2005
Unitil Energy Systems, Inc.:			
First Mortgage Bonds:			
8.49% Series, Due October 14, 2024	**$ 15,000**	$ 15,000	$ 15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000	15,000
Fitchburg Gas and Electric Light Company:			
Long-Term Notes:			
6.75% Notes, Due November 30, 2023	**19,000**	19,000	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000	10,000
5.90% Notes, Due December 15, 2030	**15,000**		15,000
Unitil Realty Corp.:			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,522**	5,819	5,673
Total	**125,522**	110,819	125,673
Less: Installments due within one year	**323**	296	308
Total Long-term Debt	**$ 125,199**	$ 110,523	$ 125,365

The fair value of the Company s long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company s long-term debt at June 30, 2006 is estimated to be in a range of up to approximately $134 million, before considering any costs, including prepayment costs, to market the Company s debt. Currently, management believes that there is no active market in the Company s debt securities, which have all been sold through private placements.

The Company provides limited guarantees on certain energy contracts entered into by its regulated subsidiary companies. The Company s policy is to limit these guarantees to two years or less. As of June 30, 2006 there are $8.0 million of guarantees outstanding and these guarantees extend through May 31, 2008. These guarantees are not required to be recorded under the provisions of FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.

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NOTE 5 SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2006 and June 30, 2005 (unaudited):

	Electric	Gas	Other	Non-Regulated	Total
Three Months Ended June 30, 2006 (000 s)					
Revenues	$ 53,328	$ 6,286	$	$ 612	$ 60,226
Segment Profit (Loss)	1,794	(466)	134	(61)	1,401
Identifiable Segment Assets	322,837	100,656	19,722	1,219	444,434
Capital Expenditures	6,385	2,273	152	2	8,812
Three Months Ended June 30, 2005 (000 s)					
Revenues	$ 46,033	$ 4,953	$ 1	$ 452	$ 51,439
Segment Profit (Loss)	1,705	(357)	158	(9)	1,497
Identifiable Segment Assets	330,146	94,733	17,162	929	442,970
Capital Expenditures	3,251	1,791	12		5,054
Six Months Ended June 30, 2006 (000 s)					
Revenues	**$ 109,758**	**$ 19,972**	**$**	**$ 1,199**	**$ 130,929**
Segment Profit (Loss)	**3,056**	**261**	**259**	**(162)**	**3,414**
Identifiable Segment Assets	**322,837**	**100,656**	**19,722**	**1,219**	**444,434**
Capital Expenditures	**11,595**	**2,696**	**145**	**2**	**14,438**
Six Months Ended June 30, 2005 (000 s)					
Revenues	$ 92,845	$ 17,640	$ 1	$ 953	$ 111,439
Segment Profit (Loss)	3,115	821	259	(27)	4,168
Identifiable Segment Assets	330,146	94,733	17,162	929	442,970
Capital Expenditures	7,276	2,195	27		9,498

NOTE 6 REGULATORY MATTERS

UNITIL S REGULATORY MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

Overview Unitil and its subsidiaries are subject to regulation as a holding company system by the FERC under the Energy Policy Act of 2005 in regards to certain bookkeeping, accounting and reporting requirements. Prior to the passage of the Energy Policy Act of 2005, Unitil and its subsidiaries were subject to regulation as a registered holding company system under the Public Utility Holding Company Act of 1935 (PUHCA) by the SEC with respect to various matters, including: the issuance of securities, capital structure, and certain acquisitions and dispositions of assets. As a result of the enactment of the Energy Policy Act of 2005, PUHCA has been repealed. Unitil s utility operations related to wholesale and interstate business activities are also regulated by FERC. The retail distribution utilities, UES and FG&E, are subject to regulation by the NHPUC and the MDTE, respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Because Unitil s primary operations are subject to rate regulation, the regulatory treatment of various matters could significantly affect the Company s operations and financial position.

Unitil s retail distribution utilities have the franchise to deliver electricity and/or natural gas to all customers in our franchise areas, at rates established under traditional cost of service regulation. Under this regulatory structure, UES and FG&E recover the cost of providing distribution service to their customers based on an historical test

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year, in addition to earning a return on their capital investment in utility assets. As a result of a restructuring of the utility industry in Massachusetts and New Hampshire, Unitil s customers have the opportunity to purchase their electric or natural gas supplies from third-party vendors. Most small and medium-sized customers, however, continue to purchase such supplies through UES and FG&E as the provider of last resort. UES and FG&E purchase electricity or natural gas from unaffiliated wholesale suppliers and recover the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

In connection with the implementation of retail choice, Unitil Power and FG&E divested their long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. UES and FG&E recover in their rates all the costs associated with the divestiture of their power supply portfolios and have secured regulatory approval from the NHPUC and MDTE, respectively, for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The remaining balance of these assets, to be recovered principally over the next five to seven years, is $140.3 million as of June 30, 2006 and is included in Regulatory Assets on the Company s Consolidated Balance Sheet. Unitil s retail distribution companies have a continuing obligation to submit filings in both states that demonstrate their compliance with regulatory mandates and provide for timely recovery of costs in accordance with their approved restructuring plans.

FG&E Electric Division FG&E s primary business is providing electric distribution service. Its current retail electric distribution rates were approved by the MDTE in 2002. FG&E is required, as the provider of last resort, to purchase and provide power through Default Service for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of June 30, 2006, approximately 53 percent of FG&E s electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

As a result of the restructuring and the divestiture of FG&E s owned generation assets and buyout of FG&E s power supply obligations, Regulatory Assets on the Company s balance sheets include the following three categories: Power Supply Buyout Obligations associated with the divestiture of its long-term purchase power obligations; Recoverable Deferred Restructuring Charges resulting from the restructuring legislation s seven year rate cap; and Recoverable Generation-related Assets associated with the divestiture of its owned generation plant. FG&E earns carrying charges on the majority of the unrecovered balances of the Recoverable Deferred Restructuring Charges. The value of FG&E s Recoverable Deferred Restructuring Charges and Recoverable Generation-related Assets was approximately $37.9 million at June 30, 2006, and $35.9 million at June 30, 2005, and is expected to be recovered in FG&E s rates over the next five to seven years. In addition, as of June 30, 2006, FG&E had recorded on its balance sheets $54.0 million as Power Supply Buyout Obligations and corresponding Regulatory Assets associated with the divestiture of its long-term purchase power contracts, which are included in Unitil s consolidated financial statements, and on which carrying charges are not earned as the timing of cash disbursements and cash receipts associated with these long-term obligations is matched through rates.

Recovery of the deferred amounts described above will be made pursuant to a Settlement Agreement among FG&E, the Massachusetts Office of the Attorney General (Attorney General), and representatives of industrial and low-income customers. The Settlement Agreement, which was approved by the MDTE in 2005, provides for a rate path to allow recovery of FG&E s deferred stranded costs.

On March 7, 2006, the MDTE approved FG&E s 2003 and 2004 annual reconciliation of costs and revenues for Transition, Transmission, Standard Offer Service, and Default Service filed under its restructuring plan. FG&E s 2005 filing, which is subject to investigation, is pending. Management believes that this filing will be approved without material changes or adjustments.

FG&E Gas Division FG&E provides natural gas delivery service to its customers on a firm or interruptible basis under unbundled distribution rates approved by the MDTE. Its current retail distribution rates were approved by the MDTE in 2002. FG&E s customers may purchase gas supplies from third-party vendors or purchase their gas from FG&E as the provider of last resort. FG&E collects its gas supply costs through a seasonal reconciling CGAC and recovers other related costs through a reconciling Local Distribution Adjustment Clause.

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FG&E Other On October 27, 2004, the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism to provide for the recovery of costs associated with the Company s employee pension benefits and PBOP expenses. FG&E is allowed to record a regulatory asset in lieu of taking a charge to expense for the difference between the level of pension and PBOP expenses that are included in its base rates and the amounts that are required to be recorded in accordance with SFAS No. 87 and SFAS No. 106, since the effective date of its last base rate change. This mechanism provides for an annual filing and rate adjustment with the MDTE. As of June 30, 2006, FG&E has a regulatory asset of $2.9 million which is included as part of Regulatory Assets in the Company s Consolidated Balance Sheets.

On November 30, 2005, the MDTE announced a change in its method for recovery of gas cost-related bad debt, and determined that it would allow for full recovery of these costs on a reconciling basis. On December 15, 2005, FG&E filed a revised CGAC tariff reflecting this change which was approved effective January 1, 2006. FG&E also requested approval to recover its under-recovered gas cost-related bad debt for 2005 of approximately $164,000. On February 24, 2006, FG&E made a similar filing for its electric division, seeking approval to recover its actual electric supply-related bad debt through Default Service rates, effective January 1, 2006, and to recover its under-recovered electric supply-related bad debt for 2005 of approximately $84,000. On April 7, 2006, the MDTE consolidated the gas and electric requests for simultaneous review. A decision on these requests is expected in 2006. As of June 30, 2006, FG&E has regulatory assets for supply-related bad debt costs of $1.0 million.

UES UES provides electric distribution service to its customers pursuant to rates approved by the NHPUC. Its current retail electric distribution rates were established under a 2002 restructuring settlement agreement. On May 1, 2004, these distribution rates were increased by $1.0 million to provide for the recovery of PBOP costs. As the provider of last resort, UES also provides its customers with electric power through Default Service at rates which reflect UES costs for wholesale supply with no profit or markup. UES also provided a Transition Service supply for all rate classes through April 30, 2006. On May 1, 2006, customers previously on Transition Service were automatically placed on Default Service. Under a NHPUC approved settlement with the Office of the Consumer Advocate and the NHPUC Staff, UES procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts on a semi-annual basis. UES recovers its costs for this service on a pass-through basis through reconciling rate mechanisms. As of June 30, 2006, approximately 83 percent of UES electric load was served by Default Service. The remaining portion was served by competitive third party suppliers.

In the 2002 restructuring settlement, the NHPUC approved the divestiture of the long-term power supply portfolio by Unitil Power and tariffs for UES for stranded cost recovery and Transition and Default Service, including certain charges that are subject to annual or periodic reconciliation or future review. As of June 30, 2006, UES had recorded on its balance sheets $48.3 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation s consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately four years. The Company does not earn carrying charges on these regulatory assets as the timing of cash receipts and cash disbursements associated with these long-term obligations is matched through rates.

On March 17, 2006, UES made its third annual reconciliation and rate filing with the NHPUC under its restructuring plan, effective May 1, 2006, including reconciliation of prior year costs and revenues for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. The NHPUC approved the filing on April 28, 2006.

On December 11, 2004, UES filed with the NHPUC a Petition for an accounting order to defer certain pension costs above those included in its base rates, until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007 (also see Note 8 below). On April 7, 2005, the NHPUC issued an order denying UES Petition for an accounting order. In its analysis denying UES request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES income and expenses would be undertaken when UES files a rate case. As discussed below, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the Pension/PBOP Adjustment Charge (PAC). As of June 30, 2006, UES has recorded deferred pension costs of $1.0 million.

On November 4, 2005, UES filed a request for a base rate increase of $4.65 million with the NHPUC. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism, and a step adjustment for certain future rate base additions. The filing also requested that temporary rates be established at current rate levels effective December 4, 2005. On February 3, 2006, the NHPUC issued an order approving the request for temporary rates. Any rate change ultimately awarded by the NHPUC will be retroactive to January 1, 2006. The overall rate filing is currently under review, with an NHPUC order anticipated before November 2006. It is anticipated that the final determination of the amount and method of recovering UES pension and PBOP costs will be decided in the pending base rate case. The Company cannot determine the ultimate outcome of this proceeding. Based on the temporary rate order and the current status of proceedings, management has recorded an estimate of expected revenue and expenses for the first six months of 2006. The estimate includes $1.7 million in estimated revenue and $1.0 million in estimated operating expenses and taxes, a net increase to operating income of $0.7 million. The impact of this estimated increase in operating income on previously reported first quarter results has been determined to be immaterial.

FERC Wholesale Power Market Restructuring FG&E, UES and Unitil Power are members of NEPOOL, formed in 1971 to assure reliable operation of the bulk power system in the most economic manner for the region. NEPOOL is governed by the NEPOOL Agreement that is filed with and subject to the jurisdiction of the FERC. The regional bulk power system is operated by an independent corporate entity, ISO-NE, in order to avoid any opportunity for conflicting financial interests between the system operator and the market-driven participants.

As of February 1, 2005, a RTO was established in New England. ISO-NE became the entity responsible for operating the RTO. The market rules and requirements to participate in the markets previously covered under the NEPOOL Agreement were transferred to the new RTO structure under control of ISO-NE. FERC approved the formation of the RTO effective February 1, 2005. Several parties have appealed various issues associated with the FERC s approval of the RTO to Federal District Court of Appeals. Those proceedings are ongoing.

On March 1, 2004, ISO-NE filed a proposal to implement LICAP in New England to allow for the imposition of incentive pricing for transmission constrained areas. UES and FG&E intervened in the proceeding. On April 11, 2006, a contested Settlement to resolve the LICAP proceeding was submitted by the FERC Settlement Judge to the FERC. It proposed transition payments for capacity until a Forward Capacity Market can be implemented, possibly by 2010. On June 16, 2006 the FERC approved the Settlement, for implementation December 1, 2006. This case is subject to a Request for Rehearing at FERC and may be subject to subsequent appeal to the Federal Courts.

The formation of an RTO, LICAP and other wholesale market changes, including changes to transmission rates, is not expected to have a material impact on Unitil s operations because of the cost recovery mechanisms for wholesale energy costs approved by the MDTE and NHPUC. It is likely, that retail rates will be significantly increased over the next several years as the Settlement is implemented.

NOTE 7 ENVIRONMENTAL MATTERS

UNITIL S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 5 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION S FORM 10-K FOR DECEMBER 31, 2005 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON FEBRUARY 22, 2006.

The Company s past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of June 30, 2006, there are no material losses reasonably possible in excess of recorded amounts. However, there can be no assurance that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs.

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Sawyer Passway MGP Site The Company continues to work with environmental regulatory agencies to identify and assess environmental issues at the former manufactured gas plant (MGP) site at Sawyer Passway, located in Fitchburg, Massachusetts. FG&E proceeded with site remediation work as specified on the Tier 1B permit issued by the Massachusetts Department of Environmental Protection (DEP), which allows the Company to work towards temporary remediation of the site. Work performed in 2002 was associated with the five-year review of the Temporary Solution submittal (Class C Response Action Outcome) under the Massachusetts Contingency Plan (MCP) that was filed for the site in 1997. Completion of this work has confirmed the Temporary Solution status of the site for an additional five years, to January 2008. A status of temporary closure requires FG&E to monitor the site until a feasible permanent remediation alternative can be developed and completed. FG&E is in the process of developing a long range plan for a Permanent Solution for the site, including alternatives for re-use of the site.

On May 13, 2004 FG&E discovered an unauthorized excavation by another property owner on the site at Sawyer Passway in which tainted soils related to MGP by-products were exposed and relocated onto property owned by FG&E. FG&E promptly reported this discovery to the DEP and subsequently received a Notice of Responsibility on May 20, 2004. FG&E has properly disposed of the relocated materials and taken other steps in accordance with DEP directives to remedy the situation. The Completion Report for this release was submitted May 9, 2005.

Since 1991, FG&E has recovered the environmental response costs incurred at this former MGP site pursuant to an MDTE approved settlement agreement between the Massachusetts Attorney General and the natural gas utilities of the Commonwealth of Massachusetts (Agreement). The Agreement allows FG&E to amortize and recover from gas customers over succeeding seven-year periods the environmental response costs incurred each year. Environmental response costs are defined to include liabilities related to manufactured gas sites, waste disposal sites or other sites onto which hazardous material may have migrated as a result of the operation or decommissioning of Massachusetts gas manufacturing facilities from 1822 through 1978. In addition, on June 9, 2006, FG&E filed suit against several of its former insurance carriers seeking coverage for past and future environmental response costs at the site. Any recovery that FG&E receives from insurance or third parties with respect to environmental response costs, net of the unrecovered costs associated therewith, are split equally between FG&E and its gas customers. The total annual charge for such costs assessed to gas customers cannot exceed five percent of FG&E s total revenue for firm gas sales during the preceding year. Costs in excess of five percent will be deferred for recovery in subsequent years.

Note 8: Pension and Postretirement Benefit Plans

The Company provides certain pension and postretirement benefit plans for its retirees and current employees including defined benefit plans, postretirement health and welfare plans, a supplemental executive retirement plan and an employee 401(k) savings plan.

Defined Benefit Pension Plan The Company sponsors the Unitil Corporation Retirement Plan (the Plan), a defined benefit pension plan covering substantially all its employees. Under the Plan retirement benefits are based upon an employee s level of compensation and length of service. The Company records annual expense and accounts for its defined benefit pension plan in accordance with SFAS No. 87.

In December 2003 and 2002, UES and FG&E filed requests with their respective state regulatory commissions for approval of accounting orders to mitigate certain accounting requirements related to pension plan assets which had been triggered by the substantial decline in the capital markets. UES and FG&E were granted approval of this regulatory accounting treatment in January 2003 and 2004. As a result of these approvals, the Company has recorded as a Regulatory Asset the amount of the Plan s unfunded Accumulated Benefit Obligation (ABO) plus one dollar. These approvals allow UES and FG&E to treat their Additional Minimum Liability (AML) as Regulatory Assets under SFAS No. 71 and avoid the reduction in equity through other comprehensive income that would otherwise be required by SFAS No. 87.

On October 27, 2004 the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism (the Pension / PBOP Adjustment Factor (PAF)) to recover the costs associated with the Company s pension and postretirement benefits other than pensions (PBOP), costs on an annually reconciling basis. As a result of this order, FG&E records a regulatory asset to recognize the deferral for the difference between the level of pension and PBOP expenses that are currently included in its base rates and the amounts that are required to be

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recorded in accordance with SFAS No. 87 and SFAS No. 106 and amortizes increases and /or decreases in that deferral balance into the PAF for recovery over a three year period. The PAF provides for an annual filing and rate adjustment with the MDTE and requires that carrying charges on prepaid or (accrued) pension and PBOP assets and liabilities be collected from, or refunded to, utility customers. In 2005, FG&E received approval of its first annual filing and rate adjustment.

The Company initiated similar discussions for a reconciling rate mechanism for the pension costs of UES with the NHPUC. On December 11, 2004, UES filed with the NHPUC a Petition for an Accounting Order to defer certain pension costs above those included in its base rates until UES filed its next base rate case, which, pursuant to the last base rate case settlement, was required to be filed no later than October 2007. On April 7, 2005, the NHPUC issued an order denying UES Petition for an accounting order. In its analysis denying UES request, the NHPUC indicated that pension expense is an ordinary category of expense included in the revenue requirement for a utility under traditional cost of service ratemaking principles and that the size and impact of increased pension expense is not clear and that a full examination of UES income and expenses would be undertaken when UES files a rate case. As discussed above, the Company filed a full base rate case on November 4, 2005, which included a request for recovery of Pension/PBOP costs through a reconciling mechanism, the PAC. UES regulatory history with the NHPUC regarding this issue taken together with ratemaking precedent concerning pension cost recovery leads management to conclude that the pension costs are probable of recovery under SFAS No. 71. As of June 30, 2006, UES has recorded deferred pension costs of $1.0 million.

The following tables show the components of net periodic pension cost, (NPPC), as well as key actuarial assumptions used in determining the various pension plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Components of NPPC (000 s)				
Service Cost	**$ 450**	$ 332	**$ 900**	$ 679
Interest Cost	**790**	792	**1,577**	1,548
Expected Return on Plan Assets	**(976)**	(837)	**(1,887)**	(1,702)
Amortization of Prior Service Cost	**27**	25	**53**	51
Amortization of Net (Gain) Loss	**306**	261	**662**	482
Subtotal NPPC	**597**	573	**1,305**	1,058
Net Amounts Capitalized and Deferred	**(68)**	(381)	**(644)**	(684)
NPPC Recognized	**$ 529**	$ 192	**$ 661**	$ 374

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately ($164,000) and $143,000 for the three and six months ended June 30, 2006, respectively, recorded as increases (decreases) to Regulatory Assets on the Company s Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $209,000 and $366,000 for the three and six months ended June 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads. Included in the above pension expense amounts for 2006 are estimated expenditures to be recognized in the Company s rate proceeding in New Hampshire, as discussed above.

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Key Assumptions (Weighted Average)	2006	2005
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50%[1]
Rate of Compensation Increase	**3.50%**	3.50%
Used to Determine NPPC:		
Discount Rate	**5.50%**	6.50%[1]
Expected Long-Term Rate of Return on Plan Assets	**8.50%**	8.50%
Rate of Compensation Increase	**3.50%**	3.50%

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions As of June 30, 2006, the Company has not yet made any contributions to the Plan for 2006. The Company is required to make a minimum contribution to its pension plan this year in the amount of $0.8 million. The Company contributed $2.5 million in 2005.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) primarily to provide health care and life insurance benefits to active employees. Prior to October 1, 2003, the Company funded certain postretirement benefits through the Unitil Retiree Trust (URT). URT was an organization of retirees, incorporated in 1993 to provide social, health and welfare benefits to its members, who are eligible former employees of the Company. Effective January 1, 2004, the PBOP Plan was amended to provide certain healthcare and life insurance benefits, which were previously provided by the URT. The Company has established Voluntary Employee Benefit Trusts, into which it funds contributions to the PBOP Plan.

In January 2004 and May 2004, the FASB issued, respectively, Statement No. 106-1 (SFAS No. 106-1) and Statement No. 106-2 (SFAS No. 106-2), Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 , (the Act). The Act includes a subsidy to a plan sponsor that is based on 28 percent of an individual beneficiary s annual prescription drug costs between $250 and $5,000 and the opportunity for a retiree to obtain a prescription drug benefit under Medicare. SFAS No. 106-1 and SFAS No. 106-2 require the disclosure of the effects, if any, of the Act on the reported measure of the accumulated postretirement benefit obligation and how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods. On January 28, 2005, the final Medicare Part D Prescription Drug Rules were posted to the Federal Register. Based on these rules, the Company s estimated PBOP Projected Benefit Obligation was reduced by $5.1 million. Also, the Company has estimated that its annual PBOP costs will be reduced by $0.4 million under the Act. These reductions are reflected in the Company s Consolidated Financial Statements. The Company s health care insurance provider has concluded that the Company s PBOP Plan is equal to or better than standard Medicare Part D coverage. Additionally, the Company s recognition of the Act is not expected to have any impact on the rate of participation in the PBOP Plan or per capita claims.

As discussed above, on October 27, 2004 the MDTE approved FG&E s request for a reconciliation rate adjustment mechanism, the PAF, to recover the costs associated with the Company s pension and PBOP costs on an annually reconciling basis. On March 15, 2004 UES filed a petition with the NHPUC for recovery of PBOP costs. UES proposed an increase to its distribution base rates of $1.0 million to provide for the recovery of these costs, effective May 1, 2004. The NHPUC approved this filing, effective May 1, 2004. As discussed above, on November 4, 2005, UES filed a request for a base rate increase of $4.65 million. The filing includes a request to recover pension and PBOP costs through an annual reconciling rate mechanism. It is anticipated that the final determination of the amount and method of recovering UES pension and PBOP costs will be decided in the base rate case. The Company cannot determine the ultimate outcome of this proceeding.

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The following tables show the components of net periodic postretirement benefit cost (NPPBC), as well as key actuarial assumptions used in determining the various PBOP Plan values:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Components of NPPBC (000 s)				
Service Cost	**$ 350**	$ 222	**$ 641**	$ 444
Interest Cost	**563**	456	**1,014**	912
Expected Return on Plan Assets	**(69)**	(15)	**(97)**	(30)
Amortization of Prior Service Cost	**340**	365	**680**	730
Amortization of Transition (Asset) Obligation	**5**	5	**11**	10
Amortization of Net (Gain) Loss	**80**	(16)	**80**	(32)
Subtotal NPPBC	**1,269**	1,017	**2,329**	2,034
Amounts Capitalized and Deferred	**(631)**	(474)	**(1,113)**	(948)
NPPBC Recognized	**$ 638**	$ 543	**$ 1,216**	$ 1,086

Included in the 2006 amounts above for Amounts Capitalized and Deferred are approximately $167,000 and $237,000 for the three and six months ended June 30, 2006, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $139,000 and $278,000 for the three and six months ended June 30, 2005, respectively, recorded as increases to Regulatory Assets on the Company s Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Weighted-Average Assumptions	**2006**	**2005**
Used to Determine Benefit Obligations:		
Discount Rate	**5.50%**	6.50%(1)
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	7.50%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013
Used to Determine NPPBC:		
Discount Rate	**5.50%**	6.50%(1)
Expected Long-Term Rate of Return on Plan Assets Union	**8.50%**	8.50%
Expected Long-Term Rate of Return on Plan Assets Non-Union	**5.50%**	5.50%
Health Care Cost Trend Rate Assumed for Next Year	**8.50%**	8.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2016**	2013

(1) In May 2005, the Company reached agreements with its union labor bargaining units for new five-year contracts, effective June 1, 2005, which resulted in amendments to the Plan. Effective for the period of June 1, 2005 through December 31, 2005, the Company lowered the assumed discount rate to 6.00%.

Employer Contributions As of June 30, 2006, the Company has made $0.8 million of contributions to the PBOP Plan during 2006. The Company presently anticipates contributing an additional $1.8 million to fund the Plan in 2006 for an estimated total of $2.6 million. The Company contributed $2.5 million in 2005.

Supplemental Executive Retirement Plan - The Company also sponsors an unfunded retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (the SERP), with participation limited to executives selected by the Board of Directors.

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The components of net periodic SERP cost are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Components of NPSC (000 s)				
Service Cost	**$ 36**	$ 24	**$ 72**	$ 48
Interest Cost	**26**	20	**52**	40
Amortization of Transition Obligation	**4**	4	**8**	8
Amortization of Net Loss	**10**	1	**20**	2
Net Periodic SERP Cost	**$ 76**	$ 49	**$ 152**	$ 98

Employer Contributions As of June 30, 2006, the Company has made payments of $36,000 to beneficiaries during 2006. The Company presently anticipates making additional benefit payments of $36,000 in 2006 for a total of $72,000.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Reference is made to the Interest Rate Risk and Market Risk sections of Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (above).

Item 4. Controls and Procedures

As of the end of the quarter covered by this Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer concluded that the Company s disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in the Company s periodic SEC filings.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fiscal quarter covered by this Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. Certain specific matters are discussed in Notes 6 and 7 to the Consolidated Financial Statements. In the opinion of Management, based upon information furnished by counsel and others, the ultimate resolution of these claims will not have a material impact on the Company s financial position.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in the Company s Form 10-K for the year-ended December 31, 2005 as filed with the Securities and Exchange Commission on February 22, 2006.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended June 30, 2006.

(b) Not applicable.

(c) Issuer repurchases are shown in the table below for the monthly periods noted:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(1)
4/1/06 4/30/06				n/a
5/1/06 5/31/06	168	$ 24.65	168	n/a
6/1/06 6/30/06				n/a
Total	168	$ 24.65	168	n/a

(1) Represents Common Stock purchased on the open market related to Board of Director Retainer Fees and Employee Length of Service Awards. Shares are not purchased as part of a specific plan or program and therefore there is no pool or maximum number of shares related to these purchases.

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Item 6. Exhibits

(a) Exhibits

Exhibit No.	Description of Exhibit	Reference
11	Computation in Support of Earnings Per Average Common Share	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.3	Certification of Chief Accounting Officer Pursuant to Rule 13a-14 of the Exchange Act, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certifications of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Unitil Corporation Press Release Dated July 28, 2006 Announcing Earnings For the Quarter Ended June 30, 2006	Filed herewith

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SIGNATURES

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

	UNITIL CORPORATION (Registrant)
Date: July 28, 2006	/s/ Mark H. Collin Mark H. Collin Chief Financial Officer
Date: July 28, 2006	/s/ Laurence M. Brock Laurence M. Brock Chief Accounting Officer