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, 2005

Commission File Number 1-8858

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☒ No ☐

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 28, 2005
Common Stock, No par value	**5,579,090 Shares**

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
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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 Company's 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 "continue" or the 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 Net Income was $1.5 million for the second quarter of 2005. Earnings per common share were $0.27 for the second quarter of 2005 compared with earnings of $0.28 per share for the second quarter of 2004. Earnings for the second quarter of 2005 reflect higher electric and gas sales to residential and commercial customers, which were offset by lower electric sales to industrial customers. Unitil also recorded higher net operating costs in the second quarter of 2005 compared to the same period a year earlier.

Through the first six months of 2005, net income was $4.2 million compared to $4.3 million for the first six months of 2004. Through the first six months of 2005, earnings per share were $0.75 compared with earnings of $0.78 per share in the first six months of 2004 reflecting lower overall gas sales compared to last year and higher year over year net operating costs, including depreciation and audit fees.

Total electric kilowatt-hour (kWh) sales decreased slightly, 0.4%, in the three months ended June 30, 2005 compared to the same period in 2004. This decrease reflects higher kWh sales to residential and commercial customers offset by lower kWh sales to industrial customers. For the six months ended June 30, 2005, total kWh sales were flat to the same period in 2004.

Combined electric and gas sales margins increased $0.8 million and $1.0 million in the three and six month periods ended June 30, 2005 compared to the same periods in 2004. The increases in electric and gas sales margins reflect an increase in gas sales in the second quarter of 2005 and increased utility rates authorized by regulators to recover certain post retirement benefit costs and electric transmission costs.

Total Operation & Maintenance (O&M) expense increased $0.2 million, or 3.7% in the three month period ended June 30, 2005 compared to the same period in 2004. For the six month period ended June 30, 2005, total O&M expense was flat compared to the same period in 2004. The increase in the three month period reflects higher audit and legal fees of $0.3 million and higher salaries and compensation costs of $0.1 million, partially offset by lower retiree and employee benefit costs of $0.2 million. For the six month period, lower retiree and employee benefit costs of $0.3 million and lower property and casualty insurance costs of $0.1 million, were offset by higher audit and legal fees of $0.4 million. The higher audit fees in both the three and six month periods include expenditures to third parties related to the Company’s costs to comply with Section 404 of the Sarbanes-Oxley Act of 2002.

Depreciation, Amortization, Taxes and Other increased $0.7 million, or 10.7% and $1.3 million, or 9.3% in the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. These increases were due to increases in depreciation and amortization on normal plant additions and regulatory assets. Interest Expense, net, increased $0.1 million, or 6.1% and $0.1 million, or 2.3% in the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. These increases were due to increases in short-term interest expense due to higher levels of short-term borrowings and higher short-term interest rates.

Operating Revenues — Electric

Electric Operating Revenues - Electric Operating Revenues, increased by $2.5 million, or 5.7%, and by $1.9 million, or 2.0%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. 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 increases in Operating Revenues reflect slightly lower sales volume and higher base rates authorized by regulators to recover certain post retirement benefit costs and internal transmission costs, and higher Purchased Electricity costs. The Purchased Electricity revenue component of Operating Revenues increased $1.6 million, or 5.5%, and $0.7 million, or 1.1%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004, reflecting higher electric commodity prices. Purchased Electricity revenues include the recovery of the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. The Company recovers the cost of Purchased Electricity in its rates at cost on a pass through basis. C&LM revenues related to electric operations increased $0.3 million, or 33.7% and $0.3 million, or 17.7%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. The increases in C&LM revenues in these periods reflect increased spending on energy efficiency programs that were implemented during those periods. The Company also recovers the costs of C&LM on a pass through basis.

Electric sales margin (Electric Operating Revenues less cost of electric sales) was $14.0 million and $27.7 million in the three and six month periods ended June 30, 2005, respectively. This represents increases of $0.6 million and $0.8 million in the three and six month periods, respectively, compared to the same periods in 2004. These increases in Electric sales margin reflect a slight decrease in electric kilowatt-hour (kWh) sales offset by the higher base rates discussed above.

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The following table details total Electric Operating Revenues and Sales Margin for the three and six month periods ended June 30, 2005 and 2004:

Electric Operating Revenues and Sales Margin (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Electric Operating Revenue:						
Residential	**$18,511**	$17,305	7.0%	**$39,502**	$37,671	4.9%
Commercial / Industrial	**27,523**	26,237	4.9%	**53,344**	53,322	0.0%
Total Electric Operating Revenue	**$46,034**	$43,542	5.7%	**$92,846**	$90,993	2.0%
Cost of Sales:						
Purchased Electricity	**$30,956**	$29,351	5.5%	**$63,282**	$62,563	1.1%
Conservation & Load Management	**1,099**	822	33.7%	**1,899**	1,614	17.7%
Gross Electric Sales Margin	**$13,979**	$13,369	4.6%	**$27,665**	$26,816	3.2%

Kilowatt-hour Sales - Unitil's total electric kWh sales decreased 0.4% in the three months ended June 30, 2005 compared to the same period in 2004 and were flat in the six month period ended June 30, 2005 compared to the same period in 2004. The decrease in the three month period reflects a 1.6% decrease in kWh sales to commercial and industrial (C&I) customers as a group, primarily due to lower consumption by some of our large industrial customers which continue to use less energy for production processes, offset by a 1.8% increase in kWh sales to residential customers, driven by customer growth and warmer weather in the latter part of the three month period in 2005. In the six month period, kWh sales to residential customers increased 1.4% over the same period in 2004, the result of steady customer growth 2005 over 2004. Sales to C&I customers during the six month period decreased 0.9% due to lower sales to large industrial customers for the same reason discussed above.

The following table details total kWh sales for the three and six months ended June 30, 2005 and 2004 by major customer class:

kWh Sales (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Residential	**148,536**	145,851	1.8%	**335,252**	330,730	1.4%
Commercial/Industrial	**265,442**	269,753	(1.6)%	**535,402**	540,143	(0.9)%
Total	**413,978**	415,604	(0.4)%	**870,654**	870,873	0.0%

Operating Revenues - Gas

Gas Operating Revenues - Gas Operating Revenues increased $0.2 million, or 4.7%, and $1.3 million, or 7.8%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. Gas Operating Revenues include the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in Operating Expenses.

The increase in Gas Operating Revenues reflects higher base rates and higher gas commodity prices and a rebound in second quarter firm therm sales. Year to date firm therm sales are 2.3% below the prior year period.

Purchased Gas revenues increased $0.1 million, or 2.8%, and $1.2 million, or 11.9%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. These increases in Purchased Gas revenues are attributable to higher gas commodity costs. Purchased Gas revenues include the recovery of the cost of gas supply as well as the other energy supply related costs. The Company recovers the cost of Purchased Gas in its rates at cost on a pass through basis. C&LM expenses related to gas operations decreased less than $0.1 million in both the three and six month periods ended June 30, 2005, compared to the same periods in 2004. The Company also recovers the costs of C&LM on a pass through basis.

Gas sales margin (Gas Operating Revenue less the costs of gas sales) was $2.0 million and $6.2 million in the three and six month periods ended June 30, 2005, respectively. This represents increases of $0.2 million and $0.1 million compared to the same periods in 2004, respectively. For the three month period, approximately 15% of the increase in gas sales margin is attributable to a 1.5% increase in firm therm sales while approximately 85% of the increase in gas sales margin is attributable to higher rates authorized by regulators to recover certain post retirement benefit costs. The increase in firm therm sales is primarily due to cooler weather during a portion of the three month period ended June 30, 2005, compared to the same period in 2004. For the six month period, the increase in sales margin reflects lower firm therm sales in 2005 compared to 2004 offset by higher rates authorized by regulators to recover the cost of post retirement benefit costs.

The following table details total Gas Operating Revenues and Margin for the three and six months ended June 30, 2005 and 2004:

Gas Operating Revenues and Sales Margin (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Gas Operating Revenue:						
Residential	**$3,029**	$2,738	10.6%	**$10,504**	$ 9,519	10.3%
Commercial / Industrial	**1,905**	1,889	0.8%	**7,110**	6,745	5.4%
Total Firm Gas Revenue	**$4,934**	$4,627	6.6%	**$17,614**	$16,264	8.3%
Interruptible Gas Revenue	**19**	103	(81.6)%	**26**	103	(74.8)%
Total Gas Operating Revenue	**$4,953**	$4,730	4.7%	**$17,640**	$16,367	7.8%
Cost of Sales:						
Purchased Gas	**$2,839**	$2,762	2.8%	**$11,263**	$10,067	11.9%
Conservation & Load Management	**99**	139	(28.8)%	**170**	220	(22.7)%
Gross Gas Sales Margin	**$2,015**	$1,829	10.2%	**$ 6,207**	$ 6,080	2.1%

Therm Sales – Unitil's total firm therm sales of natural gas increased 1.5% in the three months ended June 30, 2005 compared to the same period in 2005 and decreased 2.3% in the six months ended June 30, 2005 compared to the same period in 2004. The increase in the three month period was primarily due to higher sales to residential customers for home heating purposes during this period. The decrease in the six month period was primarily due to a milder winter heating season in 2005 compared to the prior year and lower natural gas usage by our largest customers for production processes. Sales to residential customers increased 2.1% in the three months ended June 30, 2005 and decreased 2.5% in the six months ended June 30, 2005 compared to the same periods in 2004. Sales to C&I customers increased 0.8% in the three months ended June 30, 2005 and decreased 2.0% in the six months ended June 30, 2005 compared to the same periods in 2004.

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The following table details total firm therm sales for the three and six months ended June 30, 2005 and 2004, by major customer class:

Firm Therm Sales (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Residential	**2,291**	2,244	2.1%	**7,842**	8,045	(2.5)%
Commercial/Industrial	**2,159**	2,141	0.8%	**7,654**	7,811	(2.0)%
Total	**4,450**	4,385	1.5%	**15,496**	15,856	(2.3)%

Operating Revenue - Other

Total Other Revenues increased $0.1 million, or 35.3%, and $0.2 million, or 29.0% in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. 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, 2005 and 2004:

Other Revenue (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Other	**$ 452**	$ 334	35.3%	**$953**	$739	29.0%
Total Other Revenue	**$ 452**	$ 334	35.3%	**$953**	$739	29.0%

Operating Expenses

Purchased Electricity – Purchased Electricity expenses include the cost of electric supply as well as the other energy supply related restructuring costs, including long-term power supply contract buyout costs. Purchased Electricity increased $1.6 million, or 5.5%, and $0.7 million, or 1.1%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004, 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 $0.1 million, or 2.8%, and $1.2 million, or 11.9%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. These increases in Purchased Gas are attributable to 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 $0.2 million, or 3.7% in the three month period ended June 30, 2005 compared to the same period in 2004. For the six month period ended June 30, 2005, total O&M expense was flat compared to the same period in 2004.

The increase in the three month period reflects higher audit and legal fees of $0.3 million and higher salaries and compensation costs of $0.1 million, partially offset by lower retiree and employee benefit costs of $0.2 million. For the six month period, lower retiree and employee benefit costs of $0.3 million and lower property and casualty insurance costs of $0.1 million, were offset by higher audit and legal fees of $0.4 million. The higher audit fees in both the three and six month periods include expenditures to third parties related to the Company's costs to comply with Section 404 of the Sarbanes-Oxley Act of 2002.

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 increased $0.2 million, or 24.7%, and $0.2 million, or 12.8%, in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. These increases reflect changes in spending on Energy Efficiency programs that were implemented in 2005. 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 increased $0.7 million, or 15.5% and $1.1 million, or 12.5%, for the three and six month periods ended June 30, 2005 compared to the same periods in 2004. These increases were primarily due to increased depreciation and amortization on normal plant additions and regulatory assets.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 6.2%, and $0.2 million, or 5.8%, for the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004. These increases were primarily due to higher property taxes.

Federal and State Income Taxes - Federal and State Income Taxes are lower by $0.1 million in the second quarter of 2005 compared to 2004 reflecting lower pre-tax earnings and are flat for the six month period ended June 30, 2005 compared to the same period in 2004.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on short- and long-term debt and interest on regulatory liabilities. Interest income is mainly derived from carrying charges on restructuring related stranded costs and other deferred costs recorded as regulatory assets by the Company's retail distribution utilities as approved by regulators in New Hampshire and Massachusetts. Over the long run, as deferred costs are recovered through rates, the interest income associated with these deferrals is expected to decrease. Carrying charges on regulatory assets included in Interest Expense, net were $0.6 million and $0.4 million in the three month periods ended June 30, 2005 and June 30, 2004, respectively. For the six month periods ended June 30, 2005 and June 30, 2004, carrying charges on regulatory assets were $1.1 million and $0.8 million, respectively.

Interest Expense, net, increased by $0.1 million and $0.1 million in the three and six month periods ended June 30, 2005, respectively, as compared to the same periods in 2004. Interest expense on short-term borrowings increased $0.2 million and $0.3 million in the three and six months periods ended June 30, 2005 compared to the same periods of 2004, due to higher levels of short-term borrowings and higher short-term borrowing rates. These increases in interest expense on short-term borrowings were partially offset by increased interest income on regulatory assets of less than $0.1 million and $0.1 million in the three and six month periods, respectively and by decreases in long-term interest expense of less than $0.1 million and $0.1 million in the three and six month periods, respectively.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $13.7 million during the first six months of 2005, a decrease of $7.0 million over the comparable period in 2004. This decrease in sources of cash is largely due to a non-recurring source of cash from prepaid energy costs in 2004 and other normal working capital requirements.

Cash required for Accounts Payable increased $1.7 million compared to last year, as seasonal higher purchases of electricity and natural gas from the end of the first quarter were funded. Sources of cash for Accounts Receivable, which decreased by $1.7 million over the comparable first half of 2004, due to a delay in collections on delinquent winter bills pursuant to state authorized moratoriums coupled with higher 2005 energy costs. In addition to these working capital requirements, cash required for Deferred Restructuring Charges increased by $1.8 million due to the expiration of prior year surcharge collections related to industry restructuring in New Hampshire. The Company's regulatory assets classified as Deferred Restructuring Charges will be recovered from customers in future periods. Cash requirements increased by $3.4 million for Other, net, reflecting principally the recovery of energy costs in the first quarter of 2004 as part of the Mirant bankruptcy settlement. Such energy costs had been prepaid in 2003. Offsetting the negative operating cash flows was an increase in cash of $1.6 million in Other Current Liabilities, reflecting accrued operating expenses, which are expected to be funded in future periods.

Cash used in investing activities for the six months ended June 30, 2005 was $9.5 million compared with $10.6 during the same period last year, a reduction of $1.1 million. Annual capital expenditures are presently budgeted to be $26.3 million in 2005 compared to $22.9 million expended in 2004. These 2005 capital expenditures reflect principally electric and gas utility system additions, including $2.4 million of cash outlays for the initial phase of an Advanced Metering Infrastructure (AMI) project expected to commence in the summer of 2005. Capital expenditure projections are subject to changes during the fiscal year.

Cash flows used in financing activities were $3.9 million in the first half of 2005 compared with $10.5 million in the comparable period of 2004, primarily due to the repayment of $3.6 million of short-term debt and $3.1 million of long-term debt in the prior year. Both periods reflect the payment of dividends to shareholders of approximately $3.9 million. In addition, the Company received approximately $0.5 million in the first six months of 2005 and 2004 from the sale of its Common Stock in connection with its Dividend Reinvestment and Stock Purchase Plan and 401(k) plans.

At June 30, 2005 and December 31, 2004, Unitil had an aggregate of $44.0 million and $33.0 million, respectively, in unsecured revolving lines of credit through three banks. Lines of credit were increased as of June 30, 2005 principally to satisfy Unitil's on-going construction program. The Company expects to renew its lines of credit annually on or about June 30, 2006 and anticipates that it will be able to secure, renew or replace its revolving lines of credit to meet its projected requirements. Average daily short-term borrowings during the first six months of 2005 were approximately $24.2 million, an increase of approximately $7.8 million over the comparable period in 2004. At June 30, 2005, the Company had available approximately $18.5 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $25.5 million. In addition, Unitil had approximately $3.3 million in cash at June 30, 2005.

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. Currently, these guarantees extend through January 31, 2006. As of June 30, 2005, there are $1.0 million of guarantees outstanding.

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 March 2, 2005.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas in the Company-owned retail distribution utilities: Fitchburg Gas and Electric Light Company (FG&E), and Unitil Energy Systems, Inc. (UES). Both FG&E and UES are subject to regulation by the Federal Energy Regulatory Commission (FERC). FG&E is regulated by the Massachusetts Department of Telecommunications and Energy (MDTE) and UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). Accordingly, the Company uses the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." 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 recognizes the economic effects that result from the cause and effect relationship of costs and revenues in the rate-regulated environment and specifies 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 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 contracts for the purchase of electricity 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 would require immediate recognition of any previously deferred costs, or a portion of deferred costs, in the year in which the criteria are no longer met. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of SFAS 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 subsidiaries 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 recorded. This unbilled revenue is estimated each month based on estimated customer usage by class and applicable customer rates.

Allowance for Doubtful Accounts - The Company recognizes a Provision for Doubtful Accounts as a percent of revenues 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 bad debts 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, 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 accordance with SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions", (PBOP). 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. Approximately 40% of the Company's net pension expense is capitalized as capital additions to utility plant.

Income Taxes - The Company accounts for deferred taxes under SFAS No. 109, "Accounting for 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 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 does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation - Depreciation expense is calculated based on an asset's useful life 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 if the effect of those changes is not recoverable in regulatory rate mechanisms. 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 SFAS No. 5, "Accounting for Contingencies." SFAS No. 5 applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible 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.

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 Company meets its external financing needs by issuing short-term debt. 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, 2005 and June 30, 2004 were 3.51% and 1.55%, respectively. The average interest rates on the Company's short-term borrowings for the six months ended June 30, 2005 and June 30, 2004 were 3.27% and 1.54%, respectively.

MARKET RISK

Although Unitil's utility operating companies are 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. Additionally, as discussed above and below in Regulatory Matters, the Company has divested its commodity-related contracts and therefore, has further reduced its exposure to commodity risk.

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,	
	2005	2004	2005	2004
Operating Revenues				
Electric	**$ 46,034**	$ 43,542	**$ 92,846**	$ 90,993
Gas	**4,953**	4,730	**17,640**	16,367
Other	**452**	334	**953**	739
Total Operating Revenues	**51,439**	48,606	**111,439**	108,099
Operating Expenses				
Purchased Electricity	**30,956**	29,351	**63,282**	62,563
Purchased Gas	**2,839**	2,762	**11,263**	10,067
Operation and Maintenance	**5,936**	5,725	**11,694**	11,690
Conservation & Load Management	**1,198**	961	**2,069**	1,834
Depreciation and Amortization	**5,076**	4,393	**10,302**	9,157
Provisions for Taxes:				
Local Property and Other	**1,328**	1,250	**2,814**	2,660
Federal and State Income	**795**	861	**2,200**	2,199
Total Operating Expenses	**48,128**	45,303	**103,624**	100,170
Operating Income	**3,311**	3,303	**7,815**	7,929
Non-Operating (Income) Expenses	**43**	67	**82**	109
Income Before Interest Expense	**3,268**	3,236	**7,733**	7,820
Interest Expense, Net	**1,732**	1,632	**3,487**	3,410
Net Income	**1,536**	1,604	**4,246**	4,410
Less: Dividends on Preferred Stock	**39**	58	**78**	117
Earnings Applicable to Common Shareholders	**$ 1,497**	$ 1,546	**$ 4,168**	$ 4,293
Average Common Shares Outstanding - Basic	**5,547,269**	5,504,882	**5,540,196**	5,499,568
Average Common Shares Outstanding - Diluted	**5,563,115**	5,519,913	**5,555,390**	5,514,355
Earnings Per Common Share (Basic and Diluted)	**$ 0.27**	$ 0.28	**$ 0.75**	$ 0.78
Dividends Declared Per Share of Common Stock	**$ 0.345**	$ 0.345	**$ 1.035**	$ 1.035

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

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(000's)

	(UNAUDITED) June 30, 2005	(UNAUDITED) June 30, 2004	(AUDITED) December 31, 2004
ASSETS:			
Utility Plant:			
Electric	**$230,201**	$213,607	$ 222,121
Gas	**54,237**	49,349	53,208
Common	**27,259**	27,904	28,271
Construction Work in Progress	**3,237**	6,443	4,454
Total Utility Plant	**314,934**	297,303	308,054
Less: Accumulated Depreciation	**108,807**	98,257	104,051
Net Utility Plant	**206,127**	199,046	204,003
Current Assets:			
Cash	**3,335**	3,391	3,032
Accounts Receivable – Net of Allowance for Doubtful Accounts of $501, $444 and $501	**18,050**	15,659	18,119
Accrued Revenue	**6,578**	6,537	9,754
Refundable Taxes	**—**	818	977
Materials and Supplies	**2,957**	3,047	3,080
Prepayments	**2,117**	3,131	1,771
Total Current Assets	**33,037**	32,583	36,733
Noncurrent Assets:			
Regulatory Assets	**186,544**	213,098	199,608
Prepaid Pension Costs	**9,932**	9,981	10,990
Debt Issuance Costs	**2,236**	2,253	2,265
Other Noncurrent Assets	**5,094**	4,883	3,411
Total Noncurrent Assets	**203,806**	230,215	216,274
TOTAL	**$442,970**	$461,844	$ 457,010

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

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UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS (Cont.)
(000's)

	(UNAUDITED) June 30, 2005	(UNAUDITED) June 30, 2004	(AUDITED) December 31, 2004
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 93,377**	$ 91,936	$ 94,291
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**2,102**	3,017	2,113
Long-Term Debt, Less Current Portion	**110,523**	110,821	110,675
Total Capitalization	**206,227**	205,999	207,304
Current Liabilities:			
Long-Term Debt, Current Portion	**296**	273	285
Capitalized Leases, Current Portion	**243**	537	413
Accounts Payable	**13,894**	14,416	16,249
Short-Term Debt	**25,490**	18,810	25,675
Dividends Declared and Payable	**1,975**	1,977	50
Refundable Customer Deposits	**1,757**	1,498	1,545
Taxes Payable	**2,284**	—	—
Interest Payable	**1,328**	1,328	1,328
Other Current Liabilities	**1,982**	1,006	1,366
Total Current Liabilities	**49,249**	39,845	46,911
Deferred Income Taxes	**52,596**	56,206	56,156
Noncurrent Liabilities:			
Power Supply Contract Obligations	**127,677**	153,174	140,448
Capitalized Leases, Less Current Portion	**109**	317	183
Other Noncurrent Liabilities	**7,112**	6,303	6,008
Total Noncurrent Liabilities	**134,898**	159,794	146,639
TOTAL	**$442,970**	$461,844	$ 457,010

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

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(000's)
(UNAUDITED)

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Cash Flow from Operating Activities:		
Net Income	**$ 4,246**	$ 4,410
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**10,302**	9,157
Deferred Taxes	**(2,653)**	(1,081)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**69**	1,802
Accrued Revenue	**3,176**	3,492
Taxes Refundable / Payable	**3,261**	2,998
Materials and Supplies	**123**	(186)
Prepayments and Other	**(346)**	(585)
Accounts Payable	**(2,355)**	(608)
Refundable Customer Deposits	**212**	69
Interest Payable	**—**	(28)
Other Current Liabilities	**616**	(979)
Deferred Restructuring Charges	**(2,805)**	(1,020)
Other, net	**(97)**	3,323
Cash Provided by Operating Activities	**13,749**	20,764
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(9,498)**	(10,636)
Cash (Used in) Investing Activities	**(9,498)**	(10,636)
Cash Flows from Financing Activities:		
Repayment of Short-Term Debt	**(185)**	(3,600)
Repayment of Long-Term Debt	**(141)**	(3,130)
Dividends Paid	**(3,913)**	(3,921)
Issuance of Common Stock	**546**	481
Retirement of Preferred Stock	**(11)**	(27)
Repayment of Capital Lease Obligations	**(244)**	(306)
Cash (Used in) Financing Activities	**(3,948)**	(10,503)
Net Increase (Decrease) in Cash	**303**	(375)
Cash at Beginning of Period	**3,032**	3,766
Cash at End of Period	**$ 3,335**	$ 3,391
Supplemental Cash Flow Information:		
Interest Paid	**$ 4,685**	$ 4,524
Income Taxes Paid	**1,693**	368

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

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

UNITIL'S SIGNIFICANT ACCOUNTING POLICIES ARE DESCRIBED IN NOTE 1 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2004 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON MARCH 2, 2005.

Nature of Operations - Unitil Corporation (Unitil or the Company) is registered with the Securities and Exchange Commission (SEC) as a public utility holding company under the Public Utility Holding Company Act of 1935 (PUCHA). 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 (CECo) and Exeter & Hampton Electric Company (E&H)), 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.

Unitil Power formerly functioned as the full requirements wholesale power supply provider for UES. It is currently inactive.

Unitil Realty owns and manages the Company's corporate office building and property located in Hampton, New Hampshire and leases this facility to Unitil Service under a long-term lease arrangement. 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 Resources is the Company's wholly-owned unregulated subsidiary that provides energy brokering, consulting and management related services. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides energy brokering services, as well as various energy consulting services to large commercial and industrial customers in the northeastern United States.

Basis of Presentation – Please refer to Note 1 to the Consolidated Financial Statements – "Summary of Significant Accounting Policies" of the Company's Form 10-K for the year ended December 31, 2004, as filed with the SEC on March 2, 2005, for a description of the Company's Basis of Presentation.

Recently Issued Pronouncements - In January 2004 and May 2004, the Financial Accounting Standards Board (FASB) issued, respectively, Statement No. 106-1 (SFAS 106-1) and Statement No. 106-2 (SFAS 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 106-1 and SFAS 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 $4.0 million. Additionally, the Company has estimated that its annual PBOP costs will be reduced by $0.3 million under the Act. These reductions are reflected in the Company's Consolidated Financial Statements.

In March 2005, the FASB issued FASB Staff Position (FSP) FIN 46(R)-5, “Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities.” FSP FIN 46(R)-5 addresses whether a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity (VIE) or potential VIE if certain conditions exist. The Company has determined that there are no entities that qualify as VIE’s under FIN 46 and therefore adoption of FSP FIN 46(R)-5 did not have an impact on the Company’s Consolidated Financial Statements.

In March 2005, the FASB issued FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations”, (FIN 47). FIN 47 clarifies that the term, *conditional asset retirement obligations*, as used in FASB Statement No. 143, “Accounting for Asset Retirement Obligations,” (SFAS No. 143) refers to a legal obligation to perform an asset retirement activity in which the timing and / or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Under SFAS No. 143, the fair value of a liability for an asset retirement obligation must be recorded in the period in which it is incurred, with the cost capitalized as part of the related long-lived asset and depreciated over the asset’s useful life. The Company currently accounts for all of the costs of its long lived-assets, including the cost of removal to replace these assets, in accordance with guidelines published by the FERC for Utility plant accounting. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. Consistent with regulatory utility accounting guidance, the Company does not account separately for negative salvage, or cost of retirement obligations as defined in SFAS No. 143. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value.

The Company owns and maintains local utility distribution systems and assets. The Company has not identified any material legal obligations associated with the operational retirement and replacement of its distribution property, plant and equipment which would require recording a liability for an Asset Retirement Obligation as defined in SFAS No. 143. The cost of removal that the Company is allowed to recover in its rates relates to removal cost estimates used for mass asset accounting for the various functional components of its local distribution system. Those removal costs are not asset specific and do not rise to the level of legal obligations as defined in SFAS No. 143. The Company has effectively divested of its ownership interest in generation facilities and has no ownership interest in nuclear power plants, and has no decommissioning obligations.

In December 2004, the FASB issued revised SFAS No. 123(R), “Share-Based Payment”, originally effective for periods beginning after June 15, 2005. On April 14, 2005, the SEC modified the effective implementation date. The revised implementation date requires adoption of SFAS No. 123 (R) beginning with the first interim or annual reporting period of a registrant’s first fiscal year beginning on or after December 15, 2005. 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 has already adopted the provisions of SFAS No. 123(R) as they relate to the recognition of compensation expense for stock awards and therefore there is no additional impact on the Consolidated Financial Statements.

In May 2005, the FASB issued FASB Statement No. 154, “Accounting Changes and Error Corrections”, (SFAS No. 154), which replaces Accounting Principles Board Opinion No. 20, “Accounting Changes” and FASB Statement No. 3, “Reporting Accounting Changes in Interim Financial Statements.” SFAS No. 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to do so. SFAS No. 154 also provides that (1) a change in the method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a “restatement.” The new standard is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Early adoption of this standard is permitted for accounting changes and correction of errors made in fiscal years beginning after June 1, 2005. The Company has adopted SFAS No. 154 and determined that it did not have an impact on the Company’s Consolidated Financial Statements.

Reclassifications - Certain amounts previously reported have been reclassified to conform to current year - presentation. Most significant has been the reclassification of certain expenses between Purchased Electricity, Purchased Gas and Operation and Maintenance Expenses.

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NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
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
09/24/04	11/15/04	11/01/04	$0.345
06/24/04	08/13/04	07/30/04	$0.345
03/31/04	05/14/04	04/30/04	$0.345
01/15/04	02/13/04	01/30/04	$0.345

NOTE 3 – COMMON STOCK AND PREFERRED STOCK

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.

During the second quarter of 2004, the Company sold 9,359 shares of its Common Stock, at an average price of $26.88 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of approximately $252,000 were used to reduce short-term borrowings.

The Company has a Restricted Stock Plan (the Plan). Participants in the Plan are selected by the Compensation Committee of the Board of Directors from the eligible Participants to receive an annual award of restricted shares of Company Common Stock. The Compensation Committee has the power to determine the sizes of awards; determine the terms and conditions of awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to participants; and, subject to the provisions of the Plan, amend the terms and conditions of any outstanding award to the extent such terms and conditions are within the discretion of the Compensation Committee as provided in the Plan. Awards fully vest over a period of four years at a rate of 25% each year. Prior to the end of the vesting period, the restricted shares are subject to forfeiture if the participant ceases to be employed by the Company other than due to the participant's death. The maximum number of shares of Restricted Stock available for awards to participants under the Plan is 177,500. The maximum aggregate number of shares of Restricted Stock that may be awarded in any one calendar year to any one participant is 20,000. In the event of any change in capitalization of the Company, the Compensation Committee is authorized to make proportionate adjustments to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kinds of shares available for awards and in the annual award limit. On May 12, 2003, 10,600 shares were issued in conjunction with the Plan. The aggregate market value of the restricted stock at the date of issuance, May 12, 2003, was $259,170. On April 29, 2004, 10,700 shares were issued in conjunction with the Plan. The aggregate market value of the restricted stock at the date of issuance, April 29, 2004, was $293,715. On March 8, 2005, 10,900 shares were issued in conjunction with the Plan. The aggregate market value of the restricted stock at the date of issuance, March 8, 2005, was $299,423. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period.

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Details on preferred stock at June 30, 2005, June 30, 2004 and December 31, 2004 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30, 2005	(Unaudited) June 30, 2004	(Audited) December 31, 2004
Preferred Stock			
UES Preferred Stock, Non-Redeemable, Non-Cumulative:			
6.00% Series, $100 Par Value	**$ 225**	$ 225	$ 225
UES Preferred Stock, Redeemable, Cumulative:			
8.70% Series, $100 Par Value	**—**	215	—
8.75% Series, $100 Par Value	**—**	314	—
8.25% Series, $100 Par Value	**—**	375	—
FG&E Preferred Stock, Redeemable, Cumulative:			
5.125% Series, $100 Par Value	**892**	899	899
8.00% Series, $100 Par Value	**1,210**	1,214	1,214
Total Preferred Stock	**$2,327**	$3,242	$ 2,338

NOTE 4 – LONG-TERM DEBT

Details on long-term debt at June 30, 2005, June 30, 2004 and December 31, 2004 are shown below:

(Amounts in Thousands)

	(Unaudited) June 30, 2005	(Unaudited) June 30, 2004	(Audited) December 31, 2004
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
Unitil Realty Corp.			
Senior Secured Notes:			
8.00% Notes, Due August 1, 2017	**5,819**	6,094	5,960
Total	**110,819**	111,094	110,960
Less: Installments due within one year	**296**	273	285
Total Long-term Debt	**$110,523**	$110,821	$ 110,675

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. Currently, these guarantees extend through January 31, 2006. As of June 30, 2005, there are $1.0 million of guarantees outstanding.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three and six months ended June 30, 2005 and June 30, 2004:

Three Months Ended June 30, 2005 (000's)	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$ 46,033**	**$ 4,953**	**$ 1**	**$ 452**	**$ 51,439**
Segment Profit (Loss)	**1,832**	**(484)**	**158**	**(9)**	**1,497**
Identifiable Segment Assets	**325,616**	**94,298**	**19,722**	**1,050**	**440,686**
Capital Expenditures	**3,251**	**1,791**	**12**	**—**	**5,054**
Three Months Ended June 30, 2004 (000's)					
Revenues	$ 43,542	$ 4,730	$ —	$ 334	$ 48,606
Segment Profit (Loss)	1,874	(342)	72	(58)	1,546
Identifiable Segment Assets	366,587	83,546	10,712	999	461,844
Capital Expenditures	4,859	1,405	5	—	6,269
Six Months Ended June 30, 2005 (000's)					
Revenues	**$ 92,845**	**$17,640**	**$ 1**	**$ 953**	**$ 111,439**
Segment Profit (Loss)	**3,354**	**582**	**259**	**(27)**	**4,168**
Identifiable Segment Assets	**325,616**	**94,298**	**19,722**	**1,050**	**440,686**
Capital Expenditures	**7,276**	**2,195**	**27**	**—**	**9,498**
Six Months Ended June 30, 2004 (000's)					
Revenues	$ 90,993	$16,367	$ —	$ 739	$108,099
Segment Profit (Loss)	3,429	847	151	(134)	4,293
Identifiable Segment Assets	366,587	83,546	10,712	999	461,844
Capital Expenditures	8,560	1,884	192	—	10,636

NOTE 6 – REGULATORY MATTERS

UNITIL'S REGULATORY MATTERS ARE DESCRIBED IN NOTE 6 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2004 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON MARCH 2, 2005.

Overview - As a registered holding company under PUHCA, Unitil and its subsidiaries are regulated by the Securities and Exchange Commission (SEC) with respect to various matters, including: the issuance of securities, our capital structure, and certain acquisitions and dispositions of assets. The retail distribution utilities, UES and FG&E are subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively, in regards to their rates, issuance of securities and other accounting and operational matters. Unitil's utility operations related to wholesale and interstate business activities are also regulated by the Federal Energy Regulatory Commission (FERC). 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 a historical test 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 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, as well as certain costs associated with industry restructuring, through reconciling 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 six to eight years, is $164 million as of June 30, 2005 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 under rates approved by the MDTE. Retail distribution rates for FG&E's electric operations were last set by the MDTE in December, 2002. FG&E had been required to purchase and provide power, as the provider of last resort, through either Standard Offer Service (Standard Offer) or Default Service, for retail customers who chose not to buy, or were unable to purchase, energy from a competitive supplier. The seven year term of Standard Offer Service, which included a requirement to provide service at rate levels which included a state-mandated rate reduction, expired on February 28, 2005. FG&E continues to be required to be the provider of last resort, however, and on March 1, 2005, customers previously on Standard Offer Service were automatically placed on Default Service. Prices for Default Service are set periodically based on market solicitations as approved by the MDTE. As of June 30, 2005, competitive suppliers were serving approximately 42 percent of FG&E's electric load, primarily for FG&E's largest customers.

FG&E's stranded generation-related Regulatory Assets are being amortized and recovered through the year 2009, with no carrying charges on the unamortized balance. FG&E was subject to a total rate cap for a seven year period, which expired on February 28, 2005. Any unrecovered balance of purchased power costs and stranded costs as a result of the total rate cap has been deferred, with carrying charges, for future rate recovery as a Regulatory Asset. On April 4, 2005, FG&E filed with the MDTE a Settlement Agreement with the Massachusetts Office of the Attorney General, and representatives of industrial and low-income customers, in regards to future recovery of these deferred amounts. The Settlement Agreement, which was approved by the MDTE on May 4, 2005, provides for a rate path to allow recovery of FG&E's deferred stranded costs.

The value of FG&E's generation-related and deferred-cost Regulatory Assets was approximately $35.9 million at June 30, 2005, and $33.5 million at June 30, 2004, and is expected to be recovered in FG&E's rates over the next six to eight years. In addition, as of June 30, 2005, FG&E had recorded on its balance sheets $61.8 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.

In March 2003, the MDTE opened an investigation into whether FG&E was in compliance with relevant statutes and regulations pertaining to transactions with affiliated companies and the MDTE's requirements for the pricing and procurement of Default Service. FG&E has asserted that the transaction in question with Enermetrix was not an affiliate transaction and resulted in net benefits to FG&E's customers. Hearing and briefing of the case were completed in 2003 and an MDTE decision is pending. Management believes the outcome of this matter will not have a material adverse effect on the financial position of the Company.

On November 24, 2004, FG&E filed its annual reconciliation and rate filing with the MDTE under its restructuring plan, seeking revised rates for transmission charges, transition charges, and Standard Offer fuel adjustment. The revised rates were approved to go into effect January 1, 2005, subject to further investigation. A residential customer on Standard Offer using 500 kWh per month saw a bill increase of $3.19 or 4.6% as a result of these changes. FG&E made similar filings in 2002 and 2003, which were also approved subject to further investigation. On May 19, 2005, the MDTE, after investigation, issued an order approving FG&E's 2002 filing. The 2003 and 2004 filings remain subject to investigation and final approval.

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 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 Cost of Gas Adjustment Clause (CGAC) and recovers other related costs through a reconciling Local Distribution Adjustment Clause. In 2001, the MDTE required the mandatory assignment of LDC's pipeline capacity to competitive marketers selling gas to FG&E's customers, thus protecting FG&E from exposure to costs for stranded capacity. In January 2004, the MDTE opened an investigation on whether the mandatory assignment of pipeline capacity should be continued. On June 6, 2005, the MDTE issued its order ruling that mandatory capacity assignment shall continue.

The MDTE approved FG&E's requested increase of 5.6% to winter CGAC rates effective January 1, 2005. FG&E subsequently requested and received MDTE approval of a CGAC rate decrease of 6.5% from the January 2005 rates, effective May 1, 2005.

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 Post Retirement Benefits Other than Pension (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 removes the volatility in earnings or losses that may result from requirements of existing accounting standards and provides for an annual filing and rate adjustment with the MDTE. For the twelve month period ended December 31, 2004, FG&E was allowed to defer for recovery, through the rate adjustment mechanism, pension and PBOP expenses of $1.0 million. As of June 30, 2005, FG&E has recorded a regulatory asset of $2.0 million which is included as part of Regulatory Assets in the Company's Consolidated Balance Sheets.

UES – UES provides electric distribution service to its customers pursuant to rates established under a 2002 restructuring settlement. As the provider of last resort, UES also provides its customers with electric power through either Transition or Default Service under adjustable rates that reflect UES' costs for wholesale supply. 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 surcharges that are subject to annual or periodic reconciliation or future review. As of June 30, 2005, UES had recorded on its balance sheets $65.9 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 six years.

On March 17, 2004, UES filed its first annual reconciliation and rate filing with the NHPUC under its restructuring plan, seeking revised rates for the Transition Service Charge, Default Service Charge, Stranded Cost Charge, and External Delivery Charge. In this filing, UES also sought an accounting order to defer and amortize transaction and issuance costs associated with the merger of E&H with and into CECo to form UES. The NHPUC approved this filing, effective May 1, 2004. On March 17, 2005, UES filed its second annual reconciliation and rate filing with the NHPUC. The NHPUC approved the filing on April 29, 2005, and revised rates went into effect on May 1, 2005.

On March 15, 2004 UES filed a petition with the NHPUC for recovery of post-retirement benefits (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.

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 for 2004 until UES files its next base rate case; which is required to be filed no later than October 2007 (also see Note 8 below). In its petition, UES stated that it had experienced an extraordinary increase in pension costs of 400% to 600% since its current base rates were set in 2002 and that UES is making voluntary irrevocable cash contributions, $0.6 million in 2003 and $1.0 million in 2004, to its pension plans to maintain the financial health of the plan and to offset future pension cost increases. UES argued that its proposal for deferral of these cost increases until its next base rate case was in the best interest of its customers because it would allow UES to delay seeking new rates and avoid the cost of a formal full base rate proceeding and would support the continued funding of the pension plan. 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 on UES is not clear and that a full examination of UES income and expenses will be undertaken when UES files a rate case. As a result of this order, UES intends to file for a base rate increase in 2005 to recover pension costs and other increases in costs since its last rate case.

On February 1, 2005, the Restructuring Surcharge in UES rates, which has been in place since December 2002, expired, resulting in a rate decrease of approximately one percent. The tariff allowing for collection of this charge provided for its termination when all costs had been collected which has now occurred.

On January 7, 2005, the NHPUC approved UES' petition for a one year extension of Transition Service and Default Service for rate class G1, and the associated solicitation process whereby UES intends to secure energy supplies for such extended service. As a result, UES' Transition Service supply obligation for all rate classes will end at the same time on April 30, 2006. The Company recovers the costs of Transition Service and Default Service in its rates at cost on a pass through basis and therefore changes in these expenses do not affect earnings. On March 24, 2005, the NHPUC approved the power supply agreement and proposed rates for Transition Service and Default Service for rate class G1 for the period May 1, 2005 to October 31, 2005.

On April 1, 2005, UES filed a petition with the NHPUC for approval of a plan for procurement of Default Service power supply for service commencing on May 1, 2006 for all rate classes. The proceeding is underway and a decision is expected in September 2005.

Under the 2002 restructuring plan approved by the NHPUC, Unitil Power sold the entitlements to its long-term power supply portfolio to Mirant Americas Energy Marketing LLP (MAEM) and UES purchased supplies for Transition and Default Service from MAEM for up to three years. MAEM's parent, Mirant Corporation, provided a guarantee to ensure MAEM's performance. Following the Chapter 11 bankruptcy filing by MAEM and Mirant in July, 2003, MAEM agreed to assume, and continue to perform all obligations under, its contracts with Unitil Power and UES pursuant to a settlement approved by the bankruptcy court in December 2003. As a result of the Mirant bankruptcy, UES and Unitil Power also pursued claims with Mirant in regards to the Mirant guarantee of MAEM's performance in the event of a future default. In January 2005, UES, Unitil Power and Mirant filed a settlement with the bankruptcy court under which Mirant has agreed to put in place a replacement guarantee, or comparable security, to guarantee the performance of MAEM effective beginning May 2006. That settlement was approved by the bankruptcy court on January 18, 2005.

FERC – Wholesale Power Market Restructuring – FG&E, UES and Unitil Power are members of the New England Power Pool (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 an agreement (NEPOOL Agreement) that is filed with and subject to the jurisdiction of the FERC. Under the NEPOOL Agreement and the NEPOOL Open Access Transmission Tariff (OATT), to which virtually all New England electric utilities are parties, substantially all operation and dispatching of electric generation and bulk transmission capacity in New England is performed on a regional basis. The NEPOOL Agreement and the OATT impose generating capacity and reserve obligations, and provide for the use of major transmission facilities and support payments associated therewith. The most notable benefits of NEPOOL are coordinated power system operation in a reliable manner and a supportive business environment for the development of a competitive electric marketplace. The regional bulk power system is operated by an independent corporate entity, the 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 Regional Transmission Organization (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 in orders issued March 24, 2004 and November 3, 2004 to begin operation of the RTO structure effective February 1, 2005. As a result of the formation of the RTO, companies seeking transmission service throughout New England will be able to obtain that service under common terms, with much of their focus on dealing with ISO-NE, in cooperation with the local transmission providers.

On March 1, 2004, ISO-NE filed a proposal to implement Locational Installed Capacity (LICAP) in New England to allow for the imposition of incentive pricing for transmission constrained areas. FG&E and UES have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool. On June 2, 2004 the FERC issued an order generally accepting the ISO-NE approach to LICAP, but delayed implementation until January 1, 2006. On August 31, 2004, ISO-NE substantially updated its filing. On June 15, 2005 the Administrative Law Judge issued her Initial Decision, approving ISO-NE's revised filing with limited changes. The FERC commissioners will likely rule on the LICAP Initial Decision this fall, with any implementation expected effective January 1, 2006, subject to any appeals for judicial review.

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 possible, however, that retail rates will be significantly increased over the next several years if LICAP is implemented consistent with the Initial Decision.

FERC – Other – In August 2003, Northeast Utilities (NU) filed with FERC to revise its comprehensive network service transmission rates to establish and implement a formula based rate, replacing a fixed rate tariff. A settlement among certain parties was approved by the FERC in September 2004, which reduced the allowed return on equity in the formula rates and resulted in refunds to the tariff customers, including UES The settlement did not, however, address a specific protest raised by UES that certain provisions of NU's filing were contrary to 1997 settlement NU for comprehensive network transmission service The Company pursued its dispute with NU before the FERC. On June 1, 2005 the FERC issued its decision that the NU filing was not contrary to the 1997 settlement and confirmed NU's right to bill UPC and UES according to the filed formula rate.

On March 30, 2005, NU filed an executed Distribution Service Agreement ("DSA") settlement between UES and NU with the FERC for effect on June 1, 2005. The DSA provides for cost recovery by NU for facilities used by UES that had been reclassified from transmission plant to distribution plant. On April 20, 2005 UES intervened in support of the DSA. Costs to UES under the DSA are estimated to be approximately $2 million annually. These costs are expected to be recovered through reconciling cost recovery mechanisms. On May 19, 2005 the FERC accepted NU's DSA filing and the rates went into effect on June 1, 2005.

NOTE 7 – ENVIRONMENTAL MATTERS

UNITIL'S ENVIRONMENTAL MATTERS ARE DESCRIBED IN NOTE 6 TO THE FINANCIAL STATEMENTS IN ITEM 8 OF PART II OF UNITIL CORPORATION'S FORM 10-K FOR DECEMBER 31, 2004 AS FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON MARCH 2, 2005.

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, 2005, 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.

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.

In addition, several actions have been identified to maintain the Class C Response Action Outcome and take steps toward a Permanent Solution, as required by the MCP. Work at the site during 2004 was associated with the completion of periodic groundwater monitoring to track contaminant levels over time and the disposition of contaminated soils related to MGP by-products excavated by one of the site tenants, as described below. FG&E also began developing a long range plan for a Permanent Solution for the site, including one alternative 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 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.

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, 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, "Employers' Accounting for Pensions."

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 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 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.

The Company has 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 for 2004 until its next base rate case (also see Note 6 above). In that petition the Company stated its intention to explore with the NHPUC and other interested parties, a reconciling rate mechanism for pension costs incurred by UES to achieve the same benefits for UES and its customers that have been achieved by implementing the PAF for FG&E. In its petition, UES stated that it had experienced an extraordinary increase in pension costs, of 400% to 600%, since its current base rates were set in 2002 and that UES is making voluntary irrevocable cash contributions, $0.6 million in 2003 and $1.0 million in 2004, to its pension plans to maintain the financial health of the plan and to offset future pension cost increases. UES argued that its proposal for deferral of these costs increases until its next base rate case was in the best interest of its customers because it would allow UES to delay seeking new rates and avoid the cost of a formal full base rate proceeding and would support the continued funding of the pension plan.

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 on UES is not clear and that a full examination of UES income and expenses will be undertaken when UES files a rate case. As a result of this order, UES intends to file a base rate case in 2005 to increase its base rates to recover pension costs and other increases in costs since its last rate case.

As of June 30, 2005, UES has recorded deferred pension costs of $0.9 million, which includes $0.6 million of pension costs deferred as of December 31, 2004. The NHPUC has historically permitted the recovery of prudently incurred expenditures related to pension benefits for UES’ employees. The final determination of the amount and method of recovering UES’ pension costs will be decided in its next base rate case and a decision on this proceeding would be expected in 2006. The Company cannot determine the ultimate outcome of this proceeding.

The following tables show the components of net periodic pension cost (income), (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,	
	2005	**2004**	**2005**	**2004**
Components of NPPC (000’s)				
Service Cost	**$ 332**	$ 325	**$ 679**	$ 650
Interest Cost	**792**	757	**1,548**	1,514
Expected Return on Plan Assets	**(837)**	(848)	**(1,702)**	(1,696)
Amortization of Prior Service Cost	**25**	25	**51**	50
Amortization of Net (Gain) Loss	**261**	236	**482**	472
Subtotal NPPC	**573**	495	**1,058**	990
Amounts Capitalized and Deferred	**(437)**	(303)	**(795)**	(592)
NPPC Recognized	**$ 136**	$ 192	**$ 263**	$ 398

Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $265 thousand and $478 thousand for the three and six months ended June 30, 2005, respectively, deferred and recorded as a Regulatory Asset on the Company’s Balance Sheet. Included in the 2004 amounts above for Amounts Capitalized and Deferred are approximately $148 thousand and $291 thousand for the three and six months ended June 30, 2004, respectively, deferred and recorded as a Regulatory Asset on the Company’s Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Employer Contributions – As of June 30, 2005, the Company has not yet made any contributions to the Plan for 2005. The Company is required to make a minimum contribution to its pension plan this year in the amount of $0.7 million. The Company contributed $2.0 million in 2004.

Postretirement Benefits - The Company also sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan) 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.

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.

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,	
	2005	**2004**	**2005**	**2004**
Components of NPPBC (000's)				
Service Cost	**$ 222**	$ 245	**$ 444**	$ 490
Interest Cost	**456**	497	**912**	997
Expected Return on Plan Assets	**(15)**	—	**(30)**	—
Amortization of Prior Service Cost	**365**	365	**730**	730
Amortization of Transition (Asset) Obligation	**5**	5	**10**	10
Amortization of Net (Gain) Loss	**(16)**	—	**(32)**	—
Subtotal NPPBC	**1,017**	1,112	**2,034**	2,227
Amounts Capitalized and Deferred	**(418)**	(626)	**(836)**	(1,544)
NPPBC Recognized	**$ 599**	$ 486	**$1,198**	$ 683

Included in the 2005 amounts above for Amounts Capitalized and Deferred are approximately $83 thousand and $167 thousand for the three and six months ended June 30, 2005, respectively, deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. Included in the 2004 amounts above for Amounts Capitalized and Deferred are approximately $239 thousand and $747 thousand for the three and six months ended June 30, 2004, respectively, deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amounts represent amounts capitalized to construction overheads.

Employer Contributions – As of June 30, 2005, the Company has made $0.9 million of contributions to the PBOP Plan. The Company presently anticipates contributing an additional $1.5 million to fund the Plan in 2005 for an estimated total of $2.4 million.

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,	
	2005	**2004**	**2005**	**2004**
Components of NPSC (000's)				
Service Cost	**$ 24**	$ 19	**$ 48**	$ 38
Interest Cost	**20**	17	**40**	34
Expected Return on Plan Assets	**—**	—	**—**	—
Amortization of Prior Service Cost	**—**	(1)	**—**	(2)
Amortization of Transition Obligation	**4**	4	**8**	8
Amortization of Net Loss	**1**	1	**2**	2
Net Periodic SERP Cost	**$ 49**	$ 40	**$ 98**	$ 80

Employer Contributions – As of June 30, 2005, the Company has made payments of $36,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $36,000 in 2005 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 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, 2005.

(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)]
4/1/05 – 4/30/05	—	—	—	n/a
5/1/05 – 5/31/05	176	$ 26.80	176	n/a
6/1/05 – 6/30/05	—	—	—	n/a
Total	176	$ 26.80	176	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 Controller 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 Controller 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 29, 2005 Announcing Earnings For the Quarter Ended June 30, 2005	Filed herewith

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 29, 2005	/s/ Mark H. Collin
	Mark H. Collin Chief Financial Officer
Date: July 29, 2005	/s/ Laurence M. Brock
	Laurence M. Brock Controller and Chief Accounting Officer

EXHIBIT 11

UNITIL CORPORATION AND SUBSIDIARY COMPANIES

COMPUTATION OF EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING

(000's except for per share data)

(UNAUDITED)

(000's, except per share data)	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Net Income	**$ 1,536**	$ 1,604	**$ 4,246**	$ 4,410
Less: Dividend Requirements on Preferred Stock	**39**	58	**78**	117
Net Income Applicable to Common Stock	**$ 1,497**	$ 1,546	**$ 4,168**	$ 4,293
Weighted Average Number of Common Shares Outstanding – Basic	**5,547,269**	5,504,882	**5,540,196**	5,499,568
Dilutive Effect of Stock Options and Restricted Stock	**15,846**	15,031	**15,194**	14,787
Weighted Average Number of Common Shares Outstanding – Diluted	**5,563,115**	5,519,913	**5,555,390**	5,514,355
Earnings Per Share – Basic	**$ 0.27**	$ 0.28	**$ 0.75**	$ 0.78
Earnings Per Share – Diluted	**$ 0.27**	$ 0.28	**$ 0.75**	$ 0.78

Exhibit 31.1

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert G. Schoenberger, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f))for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2005

/s/ Robert G. Schoenberger

Robert G. Schoenberger
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark H. Collin, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2005

/s/ Mark H. Collin

Mark H. Collin
Chief Financial Officer

Exhibit 31.3

CERTIFICATION UNDER SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Brock, certify that:

1) I have reviewed this quarterly report on Form 10-Q of Unitil Corporation;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any changes in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonable likely to materially affect, the registrant's internal controls over financial reporting; and

5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2005

/s/ Laurence M. Brock

Laurence M. Brock
Controller and Chief Accounting Officer

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Unitil Corporation (the “Company”) on Form 10-Q for the period ending June 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned Robert G. Schoenberger, Chief Executive Officer and President, Mark H. Collin, Chief Financial Officer and Laurence M. Brock, Controller, certifies, to the best knowledge and belief of the signatory, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Signature	Capacity	Date
/s/ Robert G. Schoenberger Robert G. Schoenberger	Chief Executive Officer and President	July 29, 2005
/s/ Mark H. Collin Mark H. Collin	Chief Financial Officer	July 29, 2005
/s/ Laurence M. Brock Laurence M. Brock	Controller and Chief Accounting Officer	July 29, 2005

For Immediate Release **Exhibit 99.1**

Contact: Mark H. Collin
Phone: 603-773-6612
Fax: 603-773-6605
Email: collin@unitil.com

Unitil Reports Second Quarter Earnings

Hampton, NH – July 29, 2005: Unitil Corporation (AMEX: UTL) (www.unitil.com) today announced net income of $1.5 million for the second quarter of 2005. Earnings per common share were $0.27 for the second quarter of 2005 compared with earnings of $0.28 per share for the second quarter of 2004. Earnings for the second quarter of 2005 reflect higher electric and gas sales to residential and commercial customers, which were offset by lower electric sales to industrial customers. Unitil also recorded higher net operating costs in the second quarter of 2005 compared to the same period a year earlier.

Through the first six months of 2005, net income was $4.2 million compared to $4.3 million for the first six months of 2004. Through the first six months of 2005, earnings per share were $0.75 compared with earnings of $0.78 per share in the first six months of 2004 reflecting lower overall gas sales compared to last year and higher year over year net operating costs, including depreciation and audit fees.

"We continue to see solid growth in our customer base led by strong residential and commercial construction. This overall trend was somewhat muted by flat sales to industrial customers and lower overall energy usage per customer primarily reflecting record high fuel prices," said Unitil Chairman, President and Chief Executive Officer Robert G. Schoenberger. "We are pleased with the continued growth of our unregulated energy brokering business, Usource, which achieved a 35% growth in revenues in the second quarter of 2005 compared to the same period in 2004."

Total electric kilowatt-hour (kWh) sales decreased slightly, 0.4%, in the three months ended June 30, 2005 compared to the same period in 2004. This decrease reflects higher kWh sales to residential and commercial customers offset by lower kWh sales to industrial customers. For the six months ended June 30, 2005, total kWh sales were flat to the same period in 2004.

Total firm therm sales of natural gas increased 1.5% in the three months ended June 30, 2005 compared to the same period in 2005 and decreased 2.3% in the six months ended June 30, 2005 compared to the same period in 2004.

Total sales margin (Revenues less Purchased Electric and Gas and Conservation & Load Management) was $16.4 million and $34.8 million in the three and six month periods ended June 30, 2005. Total sales margin for the three month period in 2005 increased $0.9 million, or 4.7% compared with the same period in 2004, and total sales margin for the six month period in 2005 represents an increase of $1.2 million, or 3.5%, compared to the same period in 2004. The increases in total sales margin reflect the increase in gas sales in the second quarter and increased utility rates authorized by regulators to recover certain post retirement benefit costs and electric transmission costs. In addition, revenues from unregulated operations showed steady improvement, increasing by $118,000, or 35.3%, and $214,000, or 29.0% in the three and six month periods ended June 30, 2005, respectively, compared to the same periods in 2004.

Total Operation & Maintenance (O&M) expense increased $0.2 million, or 3.7% in the three month period ended June 30, 2005 compared to the same period in 2004. For the six month period ended June 30, 2005, total O&M expense was flat compared to the same period in 2004. The increase in the three month period reflects higher audit and legal fees of $0.3 million and higher salaries and compensation costs of $0.1 million, partially offset by lower retiree and employee benefit costs of $0.2 million. For the six month period, lower retiree and employee benefit costs of $0.3 million and lower property and casualty insurance costs of $0.1 million, were offset by higher audit and legal fees of $0.4 million. The higher audit fees in both the three and six month periods include expenditures to third parties related to the Company's costs to comply with Section 404 of the Sarbanes-Oxley Act of 2002.

Depreciation, Amortization, Taxes and Other increased $0.7 million, or 10.7% and $1.3 million, or 9.3% in the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. These increases were due to increases in depreciation and amortization on normal plant additions and regulatory assets. Interest Expense, net, increased $0.1 million, or 6.1% and $0.1 million, or 2.3% in the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. These increases were due to increases in short-term interest expense due to higher levels of short-term borrowings and higher short-term interest rates.

Unitil is a public utility holding company with subsidiaries providing electric service in New Hampshire and electric and gas service in Massachusetts and energy services throughout the Northeast. Its subsidiaries include Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, Unitil Power Corp., Unitil Realty Corp., Unitil Service Corp. and its unregulated business segment Unitil Resources, Inc. Usource L.L.C. is a subsidiary of Unitil Resources, Inc.

This press release contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. All statements, other than statements of historical fact, are forward-looking statements. Certain factors that could cause the actual results to differ materially from those projected in these forward-looking statements include, but are not limited to the following: variations in weather; changes in the regulatory environment; customers' preferences on energy sources; general economic conditions; increased competition; fluctuations in supply, demand, transmission capacity and prices for energy commodities; and other uncertainties, all of which are difficult to predict, and many of which are beyond the control of Unitil Corporation.

The following table details total kilowatt-hour (kWh) sales of electricity for the three and six months ended June 30, 2005 and 2004, by major customer class.

kWh Sales (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Residential	**148,536**	145,851	1.8%	**335,252**	330,730	1.4%
Commercial/Industrial	**265,442**	269,753	(1.6)%	**535,402**	540,143	(0.9)%
Total	**413,978**	415,604	(0.4)%	**870,654**	870,873	0.0%

Firm Therm Sales (000's)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	**2004**	**% Change**	**2005**	**2004**	**% Change**
Residential	**2,291**	2,244	2.1%	**7,842**	8,045	(2.5)%
Commercial/Industrial	**2,159**	2,141	0.8%	**7,654**	7,811	(2.0)%
Total	**4,450**	4,385	1.5%	**15,496**	15,856	(2.3)%

Unitil Corporation

Selected Financial Information (Amounts In Thousands, except Shares and Per Share Data) (Unaudited)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2005	2004	% Change	2005	2004	% Change
Condensed Financial Data						
Operating Revenues	$ 51,439	$ 48,606	5.8%	$ 111,439	$ 108,099	3.1%
Purchased Electric and Gas and Conservation & Load Management	34,993	33,074	5.8%	76,614	74,464	2.9%
Sales Margin	16,446	15,532	5.9%	34,825	33,635	3.5%
Operation & Maintenance	5,936	5,725	3.7%	11,694	11,690	—
Depreciation, Amortization, Taxes & Other	7,199	6,504	10.7%	15,316	14,016	9.3%
Operating Income	3,311	3,303	0.2%	7,815	7,929	(1.4)%
Interest Expense, Net	1,732	1,632	6.1%	3,487	3,410	2.3%
Other	43	67	(35.8)%	82	109	(24.8)%
Net Income	1,536	1,604	(4.2)%	4,246	4,410	(3.7)%
Preferred Dividends	39	58	(32.8)%	78	117	(33.3)%
Net Income Applicable to Common Stock	$ 1,497	$ 1,546	(3.2)%	$ 4,168	$ 4,293	(2.9)%
Earnings per Common Share						
Net Income Applicable to Common Stock	$ 0.27	$ 0.28		$ 0.75	$ 0.78	
Weighted Average Common Shares Outstanding	5,563,115	5,519,913		5,555,390	5,514,355	

For more information, visit Unitil at www.unitil.com or call Mark Collin at 603-773-6612.