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 March 31, 2005

Commission File Number 1-8858

UNITIL CORPORATION

(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes_X__ No___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes_X__ 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 April 28, 2005
Common Stock, No par value	5,569,478 Shares

UNITIL CORPORATION AND SUBSIDIARY COMPANIES
FORM 10-Q
For the Quarter Ended March 31, 2005

Table of Contents

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 $2.7 million for the first quarter of 2005, $76 thousand lower than the first quarter of 2004. Results for the first quarter of 2005 compared to the prior year reflect higher quarterly gross sales margin and lower operating and maintenance expenses which were offset by higher depreciation and amortization expenses and higher property and payroll taxes. Electric gross sales margin increased by $0.3 million, primarily due to increased electric base rates to recover the cost of postretirement benefits in New Hampshire. Gas gross sales margin, which decreased by less than $0.1 million, was adversely affected by milder winter weather in the first quarter of 2005 compared to the same period in 2004.

Earnings per common share were $0.48 for the first quarter of 2005 compared with earnings of $0.50 per share for the first quarter of 2004.

Operating Revenues — Electric

Electric Operating Revenues - Electric Operating Revenue, decreased by $0.6 million, or 1.3%, in the three months ended March 31, 2005 compared to the same period in 2004. Electric Operating Revenue includes the recovery of costs of electric sales, which are recorded as Purchased Electricity and Conservation & Load Management (C&LM) in operating expenses. The decrease in Operating Revenue reflects lower Purchased Electricity costs compared to the prior period. The Purchased Electricity cost of sales component decreased $0.9 million, or 2.7%, in the three months ended March 31, 2005 compared to the same period in 2004, reflecting lower electric commodity prices. 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. The Company recovers the cost of Purchased Electricity in its rates at cost on a pass through basis. C&LM revenue related to electric operations in the first three months of 2005 was flat compared to the same period in 2004. The Company also recovers the costs of C&LM on a pass through basis.

Electric sales margin (Electric Operating Revenue less cost of electric sales) was $13.7 million in the three months ended March 31, 2005. This represents an increase of $0.3 million compared to the same period in 2004. Approximately 85% of this increase is due to increase electric base rates for the recovery of postretirement benefit costs in the Company's New Hampshire retail distribution utility while the remainder of the increase is due to an increase of 0.3% in electric kilowatt-hour (kWh) sales during the period.

The following table details total Electric Operating Revenues and Sales Margin for the three month periods ended March 31, 2005 and 2004:

Electric Operating Revenues and Sales Margin (000's)

	Three Months Ended March 31,		
	2005	2004	% Change
Electric Operating Revenue:			
Residential	**$ 20,992**	$ 20,366	3.1%
Commercial / Industrial	**25,820**	27,085	(4.7%)
Total Electric Operating Revenue	**$ 46,812**	$ 47,451	(1.3%)
Cost of Sales:			
Purchased Electricity	**$ 32,326**	$ 33,212	(2.7%)
Conservation & Load Management	**784**	786	(0.2%)
Gross Electric Sales Margin	**$ 13,703**	$ 13,453	1.9%

Kilowatt-hour Sales – Total electric kilowatt-hour sales (kWh) increased 0.3% in the first quarter of 2005 compared to the same period in 2004. Residential kWh sales increased 1.0% and sales to commercial and industrial customers decreased 0.2% during this period. The overall increase in electric energy sales reflects customer growth in our utility service territories.

The following table details total kWh sales for the three months ended March 31, 2005 and 2004 by major customer class:

kWh Sales (000's)	Three Months Ended March 31,		
	2005	2004	% Change
Residential	**186,716**	184,878	1.0%
Commercial/Industrial	**269,958**	270,391	(0.2%)
Total	**456,674**	455,269	0.3%

Operating Revenues - Gas

Gas Operating Revenues – Gas Operating Revenue increased $1.0 million, or 9.0%, in the three months ended March 31, 2005 compared to the same period in 2004. Gas Operating Revenue includes the recovery of the cost of sales, which are recorded as Purchased Gas and C&LM in operating expenses.

Purchased Gas increased $1.1 million, or 15.3%, in the three months ended March 31, 2005 compared to the same period in 2004. The increase in Purchased Gas is attributable to higher gas commodity costs. Purchased Gas costs include 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 in the first three months of 2005 was flat compared to the same period 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 $4.2 million in the first three months of 2005. This represents a decrease of less than $0.1 million compared to the same period in 2004. Total firm therm unit sales decreased 3.7% in the three months ended March 31, 2005 compared to the same period in 2004 reflecting milder winter weather in the first quarter of 2005 compared to 2004.

The following table details total Gas Operating Revenues and Margin for the three months ended March 31, 2005 and 2004:

Gas Operating Revenues and Sales Margin (000's)	Three Months Ended March 31,		
	2005	2004	% Change
Gas Operating Revenue:			
Residential	**$ 7,475**	$ 6,781	10.2%
Commercial / Industrial	**5,205**	4,856	7.2%
Total Firm Gas Revenue	**$ 12,680**	$ 11,637	9.0%
Interruptible Gas Revenue	**7**	---	n/a
Total Gas Operating Revenue	**$ 12,687**	$ 11,637	9.0%
Cost of Sales:			
Purchased Gas	**$ 8,424**	$ 7,305	15.3%
Conservation & Load Management	**87**	87	(0.2%)
Gross Gas Sales Margin	**$ 4,176**	$ 4,245	(1.6%)

Therm Sales – Total natural gas firm therm sales decreased 3.7% in the first quarter of 2005 compared to the same period in 2004. Residential gas therm sales decreased 4.3% and sales to commercial and industrial customers decreased 3.1% during this period. Gas sales were negatively impacted by milder late winter weather in the first quarter of 2005 compared to the same period in 2004.

The following table details total firm therm sales for the three months ended March 31, 2005 and 2004, by major customer class:

Firm Therm Sales (000's)	**Three Months Ended March 31,**		
	2005	2004	% Change
Residential	**5,551**	5,801	(4.3%)
Commercial/Industrial	**5,495**	5,670	(3.1%)
Total	**11,046**	11,471	(3.7%)

Operating Revenue - Other

Total Other Revenues increased $0.1 million, or 23.7%, in the three month period ended March 31, 2005 compared to the same period in 2004. This increase was 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 nine months ended September 30, 2004 and 2003:

Other Revenue (000's)	**Three Months Ended March 31,**		
	2004	2003	% Change
Other	**$ 501**	$ 405	23.7%
Total Other Revenue	**$ 501**	$ **405**	23.7%

Operating Expenses

Purchased Electricity – Purchased Electricity includes the cost of electric supply as well as the other energy supply related restructuring costs, including power supply buyout costs. Purchased Electricity decreased $0.9 million in the three months ended March 31, 2005 compared to the same period in 2004, reflecting lower 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 includes the cost of natural gas purchased and manufactured to supply the Company's total gas supply requirements. Purchased Gas increased $1.1 million, or 15.3%, in the first three months of 2005 compared to the same period in 2004. The increase in Purchased Gas is attributable to higher natural 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 decreased $0.2 million, or 3.5% in the three month period ended March 31, 2005 compared to the same period in 2004.

The decrease in the three month period reflects lower retiree and employee benefit costs compared to the same period last year, of $0.1 million, and lower property & casualty insurance and legal fees of $0.1 million. These decreases were partially offset by higher audit fees of ($0.1 million), including expenditures to third parties related to the Company's efforts in complying 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 in the three month period ended March 31, 2005 were essentially flat compared to the same period in 2004. 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 $0.5 million, or 9.7% for the three month period ended March 31, 2005 compared to the same period in 2004. This increase was primarily due to increased depreciation on normal plant additions.

Local Property and Other Taxes - Local Property and Other Taxes increased by less than $0.1 million, or 5.4%, for the three month period ended March 31, 2005 compared to the same period in 2004. This increase was due to increases in payroll and property taxes.

Federal and State Income Taxes - Federal and State Income Taxes increased by less than $0.1 million in the first quarter of 2005 compared to 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 costs associated with these deferrals are expected to decrease together with a decrease in interest income.

Interest Expense, net, decreased by less than $0.1 million in the three month period ended March 31, 2005 as compared to the same period in 2004. The decrease was the result of a reduction of $50 thousand in interest expense on long-term debt on lower levels of long-term debt, increased interest income on regulatory assets of $0.1 million, partially offset by an increase of $0.1 million in short-term interest expense due to higher levels of short-term borrowings and higher short-term borrowing rates.

CAPITAL REQUIREMENTS

Cash provided by operating activities was $8.8 million during the First Quarter of 2005, a decrease of $6.2 million over the comparable period in 2004. Decreases in sources of cash are largely due to working capital requirements. The increased use of cash for Prepayments and Other of $2.7 million is associated with prepayments for purchased power payments in 2003, which were utilized in the first quarter of 2004. Cash required for Accounts Payable increased $2.2 million compared to last year mainly due to higher costs of purchasing electricity and natural gas for our customers. Uses of cash for Accounts Receivable, which increased by $2.0 million over the comparable quarter in 2004, reflect seasonal fluctuations in the collection of revenues from our customers due to the extended length of the winter heating season this year. In addition to these working capital requirements, increases in Deferred Restructuring Charges required an additional $1.8 million in cash. Deferred Restructuring Charges are regulatory assets that will be recovered from customers in future periods. Offsetting the negative operating cash flows was an increase in cash of $0.9 million in Other, net, and the Company also collected deferred energy costs from customers that led to an increase in cash from Accrued Revenues of $0.9 million for the first quarter of 2004 compared to the same period last year.

Cash used in investing activities was relatively unchanged at $4.4 million for the three months ended March 31, 2005 and the comparable period in 2004. Annual capital expenditures are presently budgeted to be $26.3 million in 2005 compared to $22.9 million expended in 2004. These capital expenditures reflect electric and gas utility system additions, including $2.4 million of cash outlays for the initial phase of the Automated Meter Reading projects 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 $3.2 million in the first three months of 2005 compared with $11.9 million in the comparable period of 2004. Cash used for financing activities in the current period includes the repayment of short-term bank debt in the amount of $1.4 million as compared to the repayment of $7.0 million of short-term bank debt during the same period in 2004. Both periods reflect the payment of dividends to shareholders of approximately $1.9 million. During the First Quarter of 2005, normal sinking fund payments of $0.1 million were incurred while during the comparable quarter in 2004, such payments included the repayment of $3.0 million of FG&E's 8.55% Long-term Notes that matured in March, 2004.

At March 31, 2005 Unitil had an aggregate of $33.0 million, in unsecured revolving lines of credit through three banks. The Company expects to renew its lines of credit annually on or about June 30, 2005 and anticipates that it will be able to secure, renew or replace its revolving lines of credit in the future in accordance with its projected requirements. Average daily short-term borrowings during the first three months of 2005 were approximately $25.5 million, an increase of approximately $8.1 million over the comparable period in 2004. At March 31, 2005, the Company had available approximately $8.7 million of unused bank lines of credit and had short-term debt outstanding through bank borrowings of approximately $24.3 million. In addition, Unitil had $4.2 million in cash at March 31, 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. As of March 31, 2005, there are $1.0 million of guarantees outstanding and these guarantees extend through October 14, 2006.

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 position of the

Company could be materially affected and the results of operations 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 financial statements and Note 1: Summary of Significant Accounting Policies.

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) and 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS No. 71, the Company has 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 for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of 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 - 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 accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts.

Depreciation - Depreciation expense is calculated based on 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.

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 March 31, 2005 and March 31, 2004 were 3.05% and 1.55%, 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

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 6 to 8 years, is $170 million as of March 31, 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 in 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 choose not to buy, or are 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 March 31, 2005, competitive suppliers were serving approximately 37 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. In anticipation of the end of the rate cap period, FG&E had advised the MDTE that it would file a proposed plan for recovery of these deferred amounts beginning March 1, 2005. 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. Under the terms of the Settlement Agreement, and subject to approval by the MDTE, the parties have agreed to a rate path to allow recovery of FG&E's deferred stranded costs. The MDTE has docketed the Settlement Agreement for review.

The value of FG&E's generation-related and deferred-cost Regulatory Assets was approximately $35.9 million at March 31, 2005, and $32.2 million at March 31, 2004, and is expected to be recovered in FG&E's rates over the next 6 to 8 years. In addition, as of March 31, 2005, FG&E had recorded on its balance sheets $63.8 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 is 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.

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, and that proceeding is ongoing.

The MDTE granted FG&E's request to voluntarily decrease its CGAC by approximately $1.2 million in February through April 2004 by accelerating the payment of a multi-year refund pursuant to a 2001 order of the MDTE that was affirmed on appeal in January, 2004. The MDTE also approved FG&E's request to amortize these charges against future revenues. Upon expiration of this refund, the MDTE approved new CGAC rates effective May 1, 2004, reflecting a net average increase to customers of 8.6 percent. New CGAC rates effective November 1, 2004, were approved as filed resulting in an average increase to customers of 16.3% versus the then current summer rates. The MDTE approved an additional increase of 5.6% to winter CGAC rates effective January 1, 2005. FG&E has requested MDTE approval of a CGAC rate decrease of 6.5% from current (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 March 31, 2005, FG&E has recorded a regulatory asset of $1.8 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 March 31, 2005, UES had recorded on its balance sheets $70.3 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation's consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately 6 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. Action on this 2005 reconciliation filing is pending.

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 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.

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 1 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. Action on this matter is pending.

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. This case continues to be contested at FERC.

The formation of an RTO, LICAP and other wholesale market changes are 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.

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. As filed, the proposed rate change would increase UES' external transmission costs paid under the NU tariff for comprehensive network service by about $600,000 per year. UES and Unitil Power protested because certain provisions of NU's filing are contrary to a settlement reached in 1997 with NU for comprehensive network transmission service. The FERC set NU's filing for settlement discussions and accepted the new tariff effective October 28, 2003, subject to refund. A settlement among certain parties was approved by the FERC in September 2004, which reduces the allowed return on equity in the formula rates and will result in refunds to the tariff customers, including UES, but does not address a specific protest raised by UES. The Company is continuing to pursue its dispute with NU before the FERC. A FERC decision in this matter is pending. Management cannot predict the outcome of this proceeding but believes it will not have a material impact on results of operations because of rate reconciling cost recovery mechanisms approved by the NHPUC.

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 reclassed from transmission plant to distribution plant. On April 20, 2005 UES intervened in support of the DSA. Costs under the DSA are estimated to be approximately $2 million annually. These costs are expected to be recovered through reconciling cost recovery mechanisms. At this early stage, it is unclear when final FERC action will take place, but the rates are expected to go into effect on June 1, 2005, possibly subject to refund if FERC has not rendered a decision by that time.

ENVIRONMENTAL MATTERS

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 December 31, 2004, 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.

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 March 31,	
	2005	2004
Operating Revenues		
Electric	**$ 46,812**	$ 47,451
Gas	**12,687**	11,637
Other	**501**	405
Total Operating Revenues	**60,000**	59,493
Operating Expenses		
Purchased Electricity	**32,326**	33,212
Purchased Gas	**8,424**	7,305
Operation and Maintenance	**5,758**	5,965
Conservation & Load Management	**871**	873
Depreciation and Amortization	**5,226**	4,764
Provisions for Taxes:		
Local Property and Other	**1,486**	1,410
Federal and State Income	**1,405**	1,338
Total Operating Expenses	**55,496**	54,867
Operating Income	**4,504**	4,626
Non-Operating Expenses	**39**	42
Income Before Interest Expense	**4,465**	4,584
Interest Expense, Net	**1,755**	1,778
Net Income	**2,710**	2,806
Less: Dividends on Preferred Stock	**39**	59
Earnings Applicable to Common Shareholders	**$ 2,671**	$ 2,747
Average Common Shares Outstanding - Basic	**5,533,123**	5,494,255
Average Common Shares Outstanding - Diluted	**5,549,223**	5,508,797
Earnings Per Common Share (Basic and Diluted)	**$ 0.48**	$ 0.50
Dividends Declared Per Share of Common Stock	**$ 0.690**	$ 0.690

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

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

	(UNAUDITED) March 31, 2005	(UNAUDITED) March 31, 2004	(AUDITED) December 31, 2004
ASSETS:			
Utility Plant:			
Electric	**$ 225,763**	$ 211,138	$ 222,121
Gas	**53,659**	48,880	53,208
Common	**27,104**	27,720	28,271
Construction Work in Progress	**3,944**	3,583	4,454
Total Utility Plant	**310,470**	291,321	308,054
Less: Accumulated Depreciation	**105,697**	95,306	104,051
Net Utility Plant	**204,773**	196,015	204,003
Current Assets:			
Cash	**4,164**	2,560	3,032
Accounts Receivable – Net of Allowance for Doubtful Accounts of $580, $511 and $501	**21,834**	19,159	18,119
Accrued Revenue	**6,128**	7,272	9,754
Refundable (Payable) Taxes	**(2,742)**	(341)	977
Materials and Supplies	**1,952**	2,184	3,080
Prepayments and Other	**1,501**	3,132	1,771
Total Current Assets	**32,837**	33,966	36,733
Noncurrent Assets:			
Regulatory Assets	**193,381**	220,115	199,608
Prepaid Pension Costs	**10,505**	10,477	10,990
Debt Issuance Costs	**2,239**	1,822	2,265
Other Noncurrent Assets	**4,579**	5,159	3,411
Total Noncurrent Assets	**210,704**	237,573	216,274
TOTAL	**$ 448,314**	$ 467,554	$ 457,010

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

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

	(UNAUDITED) March 31, 2005	(UNAUDITED) March 31, 2004	(AUDITED) December 31, 2004
CAPITALIZATION AND LIABILITIES:			
Capitalization:			
Common Stock Equity	**$ 93,496**	$ 92,035	$ 94,291
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225	225
Preferred Stock, Redeemable, Cumulative	**2,113**	3,044	2,113
Long-Term Debt, Less Current Portion	**110,600**	110,892	110,675
Total Capitalization	**206,434**	206,196	207,304
Current Liabilities:			
Long-Term Debt, Current Portion	**290**	268	285
Capitalized Leases, Current Portion	**325**	525	413
Accounts Payable	**15,224**	16,156	16,249
Short-Term Debt	**24,275**	15,430	25,675
Dividends Declared and Payable	**1,967**	1,971	50
Refundable Customer Deposits	**1,664**	1,425	1,545
Interest Payable	**2,195**	2,020	1,328
Other Current Liabilities	**5,943**	4,226	5,607
Total Current Liabilities	**51,883**	42,021	51,152
Deferred Income Taxes	**54,042**	56,152	56,156
Noncurrent Liabilities:			
Power Supply Contract Obligations	**134,062**	159,897	140,448
Capitalized Leases, Less Current Portion	**146**	297	183
Other Noncurrent Liabilities	**1,747**	2,991	1,767
Total Noncurrent Liabilities	**135,955**	163,185	142,398
TOTAL	**$ 448,314**	$ 467,554	$ 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)

	Three Months Ended March 31, 2005	2004
Cash Flow from Operating Activities:		
Net Income	**$ 2,710**	$ 2,806
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation and Amortization	**5,226**	4,764
Deferred Tax Provision	**(1,772)**	(1,409)
Changes in Current Assets and Liabilities:		
Accounts Receivable	**(3,715)**	(1,698)
Accrued Revenue	**3,626**	2,757
Refundable Taxes	**3,719**	4,157
Materials and Supplies	**1,128**	677
Prepayments and Other	**270**	3,014
Accounts Payable	**(1,025)**	1,132
Refundable Customer Deposits	**119**	(4)
Interest Payable	**867**	664
Other Current Liabilities	**336**	(28)
Deferred Restructuring Charges	**(2,161)**	(340)
Other, net	**(503)**	(1,426)
Cash Provided by Operating Activities	**8,825**	15,066
Cash Flows from Investing Activities:		
Property, Plant and Equipment Additions	**(4,444)**	(4,367)
Cash (Used in) Investing Activities	**(4,444)**	(4,367)
Cash Flows from Financing Activities:		
Repayment of Short-Term Debt	**(1,400)**	(6,980)
Repayment of Long-Term Debt	**(70)**	(3,064)
Dividends Paid	**(1,953)**	(1,957)
Issuance of Common Stock	**299**	244
Repayment of Capital Lease Obligations	**(125)**	(148)
Cash (Used in Financing) Activities	**(3,249)**	(11,905)
Net Increase (Decrease) in Cash	**1,132**	(1,206)
Cash at Beginning of Period	**3,032**	3,766
Cash at End of Period	**$ 4,164**	$ 2,560
Supplemental Cash Flow Information:		
Interest Paid	**$ 1,460**	$ 1,603
Income Taxes Refunded	**478**	1,333

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

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.

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

Unitil also has three wholly-owned subsidiaries: Unitil Service, Unitil Realty and Unitil Resources. 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

Principles of Consolidation - In accordance with current accounting pronouncements, the Company's consolidated financial statements include the accounts of Unitil and all of its wholly-owned subsidiaries and all intercompany transactions are eliminated in consolidation.

Regulatory Accounting - The Company's principal business is the distribution of electricity and natural gas in the Company-owned retail distribution utilities: FG&E and UES. Both FG&E and UES are subject to regulation by the Federal Energy Regulatory Commission (FERC) and 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." In accordance with SFAS

No. 71, the Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered in future electric and gas retail rates.

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

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

The application of SFAS No. 71 results in the deferral of costs as regulatory assets that, in some cases, have not yet been approved for recovery by the applicable regulatory commission. Management must conclude that any costs deferred as regulatory assets are probable of future recovery in rates. However, regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's consolidated financial statements. Management believes it is probable that the Company's regulated utility companies will recover their investments in long-lived assets, including regulatory assets. The Company also has commitments under long-term contracts for the purchase of electricity 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.

Massachusetts and New Hampshire have both passed utility industry restructuring legislation and the Company has filed and implemented its restructuring plans in both states. In Massachusetts, the Company is allowed to recover certain types of costs through ongoing assessments to be included in future regulated service rates. The Company is also deferring the recovery of certain restructuring related costs in order to meet the retail rate cap imposed under the Massachusetts restructuring legislation. Based on the recovery mechanism that allows recovery of all of its stranded costs and deferred costs related to restructuring, the Company has recorded regulatory assets that it expects to fully recover in future periods. The Company expects to continue to meet the criteria for the application of SFAS No. 71 for the distribution portion of its assets and operations for the foreseeable future. If a change in accounting were to occur to the distribution portion of the Company's operations, it could have a material adverse effect on the Company's earnings and retained earnings in that year and could have a material adverse effect on the Company's ongoing financial condition as well.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of SFAS No. 71. If unable to continue to apply the provisions of SFAS No. 71, the Company would be required to apply the provisions of 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.

Cash – Cash includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits.

Goodwill and Intangible Assets – The Company does not have any goodwill recorded on its balance sheet as of March 31, 2005. There are no significant intangible assets recorded by the Company at March 31, 2005. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements – As of March 31, 2005, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements. In the ordinary course of business, the Company does contract for certain office and other equipment under operating leases and, in management's opinion, the amount of these transactions is not material.

Investments and Trading Activities – During the year, the Company does invest in U.S. Treasuries and short-term investments which traditionally have very little fluctuation in fair value. The Company does not engage in investing or trading activities involving non-exchange traded contracts or other instruments where a periodic analysis of fair value would be required for book accounting purposes.

Derivatives – The Company enters into wholesale electric and gas energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether they meet the criteria for classification as derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and / or SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." As of March 31, 2005, the Company determined that none of its wholesale electric and gas energy supply contracts met the criteria for classification as a derivative instrument.

Utility Revenue Recognition - Regulated utility revenues are based on rates approved by federal and state 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.

Revenue Recognition - Non-regulated Operations - Usource, Unitil's competitive energy brokering subsidiary, records energy brokering revenues based upon the estimated amount of electricity and gas delivered to customers through the end of the accounting period.

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 written-off receivables that are recoverable through regulatory rate reconciling mechanisms. Evaluating the adequacy of the Allowance for Doubtful Accounts requires judgment about the assumptions used in the analysis. Also, the Company has experienced periods when State regulators have extended the periods during which certain standard credit and collection activities of utility companies are suspended. In periods when account write-offs exceed estimated levels, the Company adjusts the Provision for Doubtful Accounts to maintain an adequate Allowance for Doubtful Accounts balance.

Pension and Postretirement Benefit Obligations - The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in accordance with SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions." 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.

Use of Estimates - The preparation of 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 requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company prepares its financial statements in conformity with the guidance provided in The American Institute of Certified Public Accountant's Statement of Position 94-6, "Disclosure of Certain Significant Risks and Uncertainties".

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.

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

Depreciation and Amortization – 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.

Amortization provisions include the recovery of a portion of FG&E's former investment in Seabrook Station, a nuclear generating unit, in rates to its customers through the Seabrook Amortization Surcharge as ordered by the MDTE. In addition, FG&E is amortizing the balance of its unrecovered electric generating related assets, which are recorded as Regulatory Assets, in accordance with its electric restructuring plan approved by the MDTE (See Note 6).

Environmental Matters - The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has recently performed work on two environmental remediation projects, the Sawyer Passway MGP Site and the Former Electric Generating

Station. The Company has or will recover substantially all of the cost of the work performed to date from customers or from its insurance carriers. The Company is in general compliance with all applicable environmental and safety laws and regulations, and management believes that as of March 31, 2005, there are no material losses that would require additional liability reserves to be recorded. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Stock-based Employee Compensation - Unitil accounts for stock-based employee compensation currently using the fair value based method.

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

Dividends – The Company is currently paying a dividend at an annual rate of $1.38 per common share. The Company's dividend policy is reviewed annually by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

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 does 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.

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.

NOTE 2 – DIVIDENDS DECLARED PER SHARE

Declaration Date	Date Paid (Payable)	Shareholder of Record Date	Dividend Amount
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 first quarter of 2005, the Company sold 10,921 shares of its Common Stock, at an average price of $27.38 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $299,045 were used to reduce short-term borrowings.

On April 17, 2003, the Company's shareholders ratified and approved a Restricted Stock Plan (the Plan) which had been approved by the Company's Board of Directors at its January 16, 2003 meeting. 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.

During the first quarter of 2004, the Company sold 9,130 shares of its Common Stock, at an average price of $26.73 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan and its 401(k) plans. Net proceeds of $244,020 were used to reduce short-term borrowings.

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

(Amounts in Thousands)

	(Unaudited) March 31,		(Audited) December 31,
	2005	2004	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	**899**	922	899
8.00% Series, $100 Par Value	**1,214**	1,218	1,214
Total Preferred Stock	**$2,338**	$3,269	$2,338

NOTE 4 – LONG-TERM DEBT

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

(Amounts in Thousands)

	(Unaudited) March 31,		(Audited) December 31,
	2005	2004	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	**5,890**	6,160	5,960
Total	**110,890**	111,160	110,960
Less: Installments due within one year	**290**	268	285
Total Long-term Debt	**$ 110,600**	$ 110,892	$ 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. As of March 31, 2005, there are $1.0 million of guarantees outstanding and these guarantees extend through October 14, 2006.

NOTE 5 – SEGMENT INFORMATION

The following table provides significant segment financial data for the three months ended March 31, 2005 and March 31, 2004:

Three Months Ended March 31, 2005 (000's)	**Electric**	**Gas**	**Other**	**Non-Regulated**	**Total**
Revenues	**$ 46,812**	**$ 12,687**	**$ ---**	**$ 501**	**$ 60,000**
Segment Profit (Loss)	**1,522**	**1,066**	**101**	**(18)**	**2,671**
Identifiable Segment Assets	**328,953**	**96,974**	**21,387**	**1,000**	**448,314**
Capital Expenditures	**4,025**	**404**	**15**	**---**	**4,444**
Three Months Ended March 31, 2004 (000's)					
Revenues	$ 47,451	$ 11,637	$ ---	$ 405	$ 59,493
Segment Profit (Loss)	1,555	1,189	79	(76)	2,747
Identifiable Segment Assets	358,618	83,864	23,955	1,458	467,895
Capital Expenditures	3,701	479	187	---	4,367

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 6 to 8 years, is $170 million as of March 31, 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 in 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 choose not to buy, or are 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 March 31, 2005, competitive suppliers were serving approximately 37 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. In anticipation of the end of the rate cap period, FG&E had advised the MDTE that it would file a proposed plan for recovery of these deferred amounts beginning March 1, 2005. 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. Under the terms of the Settlement Agreement, and subject to approval by the MDTE, the parties have agreed to a rate path to allow recovery of FG&E's deferred stranded costs. The MDTE has docketed the Settlement Agreement for review.

The value of FG&E's generation-related and deferred-cost Regulatory Assets was approximately $35.9 million at March 31, 2005, and $32.2 million at March 31, 2004, and is expected to be recovered in FG&E's rates over the next 6 to 8 years. In addition, as of March 31, 2005, FG&E had recorded on its balance sheets $63.8 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 is 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.

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, and that proceeding is ongoing.

The MDTE granted FG&E's request to voluntarily decrease its CGAC by approximately $1.2 million in February through April 2004 by accelerating the payment of a multi-year refund pursuant to a 2001 order of the MDTE that was affirmed on appeal in January, 2004. The MDTE also approved FG&E's request to amortize these charges against future revenues. Upon expiration of this refund, the MDTE approved new CGAC rates effective May 1, 2004, reflecting a net average increase to customers of 8.6 percent. New CGAC rates effective November 1, 2004, were approved as filed resulting in an average increase to customers of 16.3% versus the then current summer rates. The MDTE approved an additional increase of 5.6% to winter CGAC rates effective January 1, 2005. FG&E has requested MDTE approval of a CGAC rate decrease of 6.5% from current (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 March 31, 2005, FG&E has recorded a regulatory asset of $1.8 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 March 31, 2005, UES had recorded on its balance sheets $70.3 million as Power Supply Contract Obligations and corresponding Regulatory Assets associated with these long-term purchase power stranded costs, which are included in Unitil Corporation’s consolidated financial statements. These Power Supply Contract Obligations are expected to be recovered principally over a period of approximately 6 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. Action on this filing is pending.

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 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.

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 1 percent. The tariff allowing for collection of this charge providedfor 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. Action on this matter is pending.

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. This case continues to be contested at FERC.

The formation of an RTO, LICAP and other wholesale market changes are 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.

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. As filed, the proposed rate change would increase UES' external transmission costs paid under the NU tariff for comprehensive network service by about $600,000 per year. UES and Unitil Power protested because certain provisions of NU's filing are contrary to a settlement reached in 1997 with NU for comprehensive network transmission service. The FERC set NU's filing for settlement discussions and accepted the new tariff effective October 28, 2003, subject to refund. A settlement among certain parties was approved by the FERC in September 2004, which reduces the allowed return on equity in the formula rates and will result in refunds to the tariff customers, including UES, but does not address a specific protest raised by UES. The Company is continuing to pursue its dispute with NU before the FERC. A FERC decision in this matter is pending. Management cannot predict the outcome of this proceeding but believes it will not have a material impact on results of operations because of rate reconciling cost recovery mechanisms approved by the NHPUC.

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 reclassed from transmission plant to distribution plant. On April 20, 2005 UES intervened in support of the DSA. Costs under the DSA are estimated to be approximately $2 million annually. These costs are expected to be recovered through reconciling cost recovery mechanisms. At this early stage, it is unclear when final FERC action will take place, but the rates are expected to go into effect on June 1, 2005, possibly subject to refund if FERC has not rendered a decision by that time.

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 December 31, 2004, 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 March 31, 2005, UES has recorded deferred pension costs of $0.7 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 table shows the components of net periodic pension cost (income), (NPPC):

		Three Months Ended March 31,		
		2005		2004
Components of NPPC (000's)				
Service Cost	**$**	**347**	$	325
Interest Cost		**756**		757
Expected Return on Plan Assets		**(865)**		(848)
Amortization of Prior Service Cost		**25**		25
Amortization of Net (Gain) Loss		**222**		236
Subtotal NPPC		**485**		495
Amounts Capitalized and Deferred		**(359)**		(290)
NPPC Recognized	**$**	**126**	$	205

Included in the 2005 and 2004 amounts above for Amounts Capitalized and Deferred are $213 thousand and $143 thousand, 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 March 31, 2005, the Company has not made any contributions to the Plan for 2005. The Company is not required to make a funding of its pension plan this year but may elect to do so. 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 table shows the components of net periodic postretirement benefit cost (NPPBC):

		Three Months Ended March 31,		
		2005		2004
Components of NPPBC (000's)				
Service Cost	**$**	**222**	$	**245**
Interest Cost		**456**		**497**
Expected Return on Plan Assets		**(15)**		**---**
Amortization of Prior Service Cost		**365**		**365**
Amortization of Transition (Asset) Obligation		**5**		**5**
Amortization of Net (Gain) Loss		**(16)**		**---**
Subtotal NPPBC		**1,017**		**1,112**
Amounts Capitalized and Deferred		**(418)**		**(917)**
NPPBC Recognized	**$**	**599**	$	**195**

Included in the 2005 and 2004 amounts above for Amounts Capitalized and Deferred are $83 thousand and $508 thousand, respectively, deferred and recorded as a Regulatory Asset on the Company's Balance Sheet. The remaining amounts in 2005 and 2004 represent amounts capitalized to construction overheads.

Employer Contributions – As of March, 2005, the Company has made $0.4 million of contributions to the PBOP Plan. The Company presently anticipates contributing an additional $2.0 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.

The components of net periodic SERP cost are as follows:

	Three Months Ended March 31,	
	2005	2004
Components of NPPC (000's)		
Service Cost	**$ 24**	$ 19
Interest Cost	**20**	17
Expected Return on Plan Assets	**---**	---
Amortization of Prior Service Cost	**---**	(1)
Amortization of Transition Obligation	**4**	4
Amortization of Net Loss	**1**	1
Net Periodic SERP Cost	**$ 49**	$ 40

Employer Contributions – As of March 31, 2005, the Company has made payments of $18,000 to beneficiaries. The Company presently anticipates making additional benefit payments of $54,000 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 Controller, 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 Controller 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 March 31, 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)
1/1/05 – 1/31/05	---	---	---	n/a
2/1/05 – 2/28/05	133	$27.06	133	n/a
3/1/05 – 3/31/05	631	$27.56	631	n/a
Total	764	$26.90	764	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.

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 April 29, 2005 Announcing Earnings For the Quarter Ended March 31, 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: April 29, 2005

/s/ Mark H. Collin
Mark H. Collin
Chief Financial Officer

Date: April 29, 2005

/s/ Laurence M. Brock
Laurence M. Brock
Controller