UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

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 offices)	**(Zip Code)**

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

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, No Par Value	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

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

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

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

Based on the closing price of June 30, 2004, the aggregate market value of common stock held by non-affiliates of the registrant was $143,360,469.

The number of common shares outstanding of the registrant was 5,556,534 as of March 1, 2005.

Documents Incorporated by Reference:

Portions of the Proxy Statement relating to the Annual Meeting of Shareholders to be held April 21, 2005, are incorporated by reference into Part III of this Report.

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PART I

Item 1. Business

UNITIL CORPORATION

Unitil Corporation (Unitil or the Company) was incorporated under the laws of the State of New Hampshire in 1984. Unitil is a registered public utility holding company under the Public Utility Holding Company Act of 1935 (PUHCA). The following companies are wholly-owned subsidiaries of Unitil:

Unitil Corporation Subsidiaries	State and Year of Organization	Principal Type of Business
Unitil Energy Systems, Inc. (UES)	NH - 1901	Retail Electric Distribution Utility
Fitchburg Gas and Electric Light Company (FG&E)	MA - 1852	Retail Electric & Gas Distribution Utility
Unitil Power Corp. (Unitil Power)	NH - 1984	Wholesale Electric Power Utility
Unitil Service Corp. (Unitil Service)	NH - 1984	Utility Service Company
Unitil Realty Corp. (Unitil Realty)	NH - 1986	Real Estate Management
Unitil Resources, Inc. (Unitil Resources)	NH - 1993	Non-utility, Unregulated Energy Services
Usource Inc., Usource L.L.C. (Usource)	NH - 2000	Energy Brokering and Advisory Services

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 our two utility subsidiaries, UES and FG&E, collectively referred to as the retail distribution utilities. Unitil's retail distribution utilities serve approximately 97,500 electric customers and 15,000 natural gas customers in their franchise areas. The retail distribution companies are local "pipes and wires" utility distribution companies with a combined investment in net utility plant of $204.0 million at December 31, 2004. Unitil's total revenue was $214.1 million in 2004. Earnings applicable to common shareholders for 2004 was $8.0 million. Substantially all of Unitil's revenue and earnings are derived from regulated utility operations.

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 those contracts.

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

OPERATIONS

Electric Utility Operations

Unitil's electric utility operations are conducted through the retail distribution utilities, UES and FG&E. Revenue from Unitil's electric utility operations was $183.9 million for 2004. Earnings from electric utility operations were $6.6 million for the same 12-month period.

The primary business of the Company's electric utility operations is the local distribution of electricity to customers in the retail distribution utilities' franchise areas. As a result of the implementation of retail choice in

New Hampshire and Massachusetts, Unitil's customers are free to contract for their supply of electricity with third-party suppliers. Both UES and FG&E supply electricity to those customers who do not obtain their supply from third-party suppliers, with the costs associated with electricity supplied by the Company being recovered on a pass-through basis under periodically-adjusted rates.

UES distributes electricity to approximately 70,300 customers in New Hampshire in the capital city of Concord as well as 12 surrounding towns and all or part of 16 towns in the southeastern and seacoast regions of New Hampshire, including the towns of Hampton, Exeter, Atkinson and Plaistow. UES' franchise areas consist of approximately 408 square miles. The state capital of New Hampshire is located within UES' franchise areas, and includes the executive, legislative and judicial branches and offices and facilities for all major state government services as well as several federal government facilities. In addition, UES' franchise areas are retail trading and recreation centers for the north central and southeastern parts of the state. These areas serve diversified commercial and industrial businesses, including manufacturing firms engaged in the production of electronic components, wires and plastics. UES' franchise areas include popular resort areas and beaches along the Atlantic Ocean, including the Hampton Beach recreational area. UES' 2004 retail electric operating revenue was $124.0 million, of which approximately 41% was derived from residential sales and 59% from commercial/industrial sales. UES' earnings in 2004 were $3.7 million.

FG&E is engaged in the retail distribution of both electricity and natural gas in the city of Fitchburg and several surrounding communities. FG&E's franchise area encompasses approximately 170 square miles. Electricity is supplied and distributed by FG&E to approximately 27,200 customers in the communities of Fitchburg, Ashby, Townsend and Lunenburg. FG&E's industrial customers include paper manufacturing and paper products companies, rubber and plastics manufacturers, chemical products companies and printing, publishing and associated industries. FG&E's 2004 retail electric operating revenue was $59.9 million, of which approximately 41% was derived from residential sales and 59% from commercial/industrial sales. FG&E's earnings from electric utility operations were $2.9 million in 2004.

Gas Utility Operations

Natural gas is supplied and distributed by FG&E to approximately 15,000 retail customers in the communities of Fitchburg, Lunenburg, Townsend, Ashby, Gardner and Westminster, all located in Massachusetts. Earnings from FG&E's gas utility operations were $1.2 million for 2004.

As a result of the introduction of retail choice for all natural gas customers in Massachusetts, FG&E's customers are free to contract for their supply of natural gas with third-party suppliers. FG&E continues to provide natural gas supply services to those customers who do not obtain their supply from third-party suppliers. The costs associated with natural gas supplied by FG&E are recovered on a pass-through basis under periodically adjusted rates.

FG&E's 2004 gas operating revenue was $28.7 million, of which approximately 54% was derived from residential firm sales and 46% from commercial/industrial firm sales.

Seasonality

Natural gas sales in New England are seasonal, and the Company's results of operations reflect this seasonal nature. Accordingly, results of operations are typically positively impacted by gas operations during the five heating season months, from November through March. Electric sales in New England are far less seasonal than natural gas sales; however, the highest usage typically occurs in both the summer due to air conditioning demand and the winter months due to heating-related requirements and shorter days.

Non-Utility, Unregulated Operations and Other

Unitil's non-utility, unregulated operations are comprised of Unitil Resources and Usource. Unitil Resources provides energy consulting and management services to customers outside the Unitil system of affiliates. Usource provides energy brokering and consulting services to large commercial and industrial customers in the northeastern United States. Revenue from Unitil's unregulated operations was $1.6 million in 2004. Unitil's other subsidiaries include Unitil Service and Unitil Realty, which provide centralized facilities, management and administrative services to Unitil's affiliated companies. Unitil's consolidated net income includes the earnings of the holding company and these subsidiaries. The earnings of these subsidiaries are principally derived from income earned on short-term investments and real property owned for Unitil's and its subsidiaries' use and is reported in Other segment income. Non-utility, unregulated operations and Other segment earnings for 2004 were approximately $0.2 million.

(For details on Unitil's Results of Operations, see Part II, Item 7 herein.)
(For segment information, see Part II, Item 8, Note 11 herein.)

RATES AND REGULATION

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 Massachusett's 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 $176 million as of December 31, 2004 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.

ELECTRIC POWER SUPPLY

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers, though most customers continue to purchase such supplies through the retail distribution utilities. The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies which provided the flexibility for migration of customers to and from utility service, and the continuation of transmission arrangements for all customers, since this function has not been opened to retail choice and continues to be performed by the local utility. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased and Unitil Power sold its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement UES continues to pay contract release payments to Unitil Power for costs associated with the portfolio sale and its other ongoing, power supply-related costs. Recovery of the contract release payments by UES from its retail customers has been approved by the NHPUC.

Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation, Mirant Americas Energy Marketing, LP (Mirant), which was approved by the NHPUC on March 14, 2003. The purchase of power to supply UES' Transition Service and Default Service requirements by UES from Mirant was linked to the Unitil Power divestiture. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. The divested power supply contracts continue through October 2010.

FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc., a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units, Millstone 3 and Wyman Unit No. 4, to Select Energy. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased. Effective with the termination of the Purchased Power Contract between FG&E and Linweave, Inc. on December 1, 2004, this portion of the contract sale also ceased.

Recovery of all costs associated with the sale of the FG&E power supply portfolio and with transmission payments from FG&E's retail customers has been approved by the MDTE.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers. In particular, FG&E has entered into power supply contracts to meet its power supply obligations associated with the provision of Standard Offer Service and Default Service. Standard Offer Service is offered only to customers who have both taken service from FG&E since the inception of retail choice in 1998 and have not switched to a competitive retail supplier. All other FG&E customers are eligible for Default Service. FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements.

Currently, the MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer duration in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES has entered into a power supply contract to meet its power supply obligations associated with the provision of Transition Service and Default Service. Transition Service is available to any UES customer who has not chosen a competitive retail supplier. UES' Default Service is available to any customer who has chosen a competitive retail energy supplier. UES has entered into a power supply contract for the provision of Transition Service and Default Service with Mirant. This power supply contract provides fixed unit prices for both Transition Service and Default Service for UES' largest general service accounts through April 2005 and for all other accounts through April 2006.

On July 14, 2003 Mirant Corporation and its subsidiaries filed for Chapter 11 Bankruptcy protection. On December 11, 2003 the bankruptcy court entered an order, which accepted a settlement agreement between Unitil and Mirant, under which Mirant agreed to assume both the power supply contract divestiture between Unitil Power and Mirant and the power supply contract for Transition Service and Default Service between UES and Mirant. Mirant is currently performing all of its contractual obligations to both Unitil Power and UES and has satisfied all of its pre-petition claims made by Unitil.

On October 26, 2004, UES filed with the NHPUC for the authority to offer Transition Service to its largest general service customers for one year, beginning May 2005 and ending April 2006. UES also proposed to contract for two 6-month contracts for a replacement supply contract for Transition Service and Default Service. On January 7, 2005 the NHPUC approved UES' filing. UES intends to file a comprehensive proposal with the NHPUC, which will address power supply procurement after April 30, 2006.

Regional Transmission and Power Markets

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 Independent System Operator-New England (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. UES and FG&E have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. 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 the 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.

GAS SUPPLY

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E purchases natural gas from domestic and Canadian suppliers under contracts of one year or less, as well as from producers and marketers on the spot market and arranges for the transportation to its distribution facilities under firm long-term contracts with the Tennessee interstate pipeline. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2002 through 2004.

Sources of Gas Supply

(Expressed as percent of total MMBtu of gas purchased)

	2004	2003	2002
Natural Gas:			
Domestic firm	**85.0%**	94.0%	73.9%
Canadian firm	**5.4%**	1.3%	8.4%
Domestic spot market	**5.9%**	1.3%	16.2%
Total natural gas	**96.3%**	96.6%	98.5%
Supplemental gas	**3.7%**	3.4%	1.5%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2004	2003	2002
Cost of gas purchased and sold per MMBtu	**$8.42**	$7.14	$ 4.96
Percent Increase (Decrease) from prior year	**17.9%**	43.9%	(30.4%)

FG&E has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

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.

Former Electric Generating Station—In 2003, FG&E completed environmental remediation action to abate and remove asbestos-containing and other hazardous materials at a former electric generating station located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware. FG&E received significant coverage from its insurance carrier for this remediation project and the resolution of this matter did not have a material adverse effect on the Company's financial position.

EMPLOYEES

As of December 31, 2004, the Company and its subsidiaries had 317 employees. Management considers the Company's relationship with employees to be good and has not experienced any major labor disruptions since the early 1960's.

There are approximately 100 employees represented by labor unions. These employees are covered by collective bargaining agreements, which expire May 31, 2005. The agreements provide discreet salary adjustments, established work practices and provided uniform benefit packages. The Company expects to successfully negotiate new agreements prior to their expiration dates.

AVAILABLE INFORMATION

The Company's Internet address is www.unitil.com. There, the Company makes available, free of charge, its SEC fillings, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other reports, as well as amendments to those reports. These reports are made available through the Investors section of Unitil's website via a direct link to the section of the SEC's website which contains Unitil's SEC filings.

The Company's current Code of Ethics was approved by Unitil's Board of Directors on January 15, 2004. This Code of Ethics, along with any amendments or waivers, is also available on Unitil's website.

Unitil's common stock is listed on the American Stock Exchange under the ticker symbol "UTL."

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides information about our directors and senior management as of March 2, 2005:

Name	Age	Position
Robert G. Schoenberger	54	Chairman of the Board, Chief Executive Officer and President
Mark H. Collin	46	Senior Vice President, Chief Financial Officer and Treasurer
Thomas P. Meissner, Jr.	42	Senior Vice President, Operations
George R. Gantz	53	Senior Vice President, Customer Services and Communications
George E. Long, Jr.	48	Vice President, Administration
Raymond J. Morrissey	57	Vice President, Information Systems
Todd R. Black	40	Vice President, Energy Markets
Laurence M. Brock	51	Vice President and Controller
David K. Foote	57	Vice President, Energy Contracts
Sandra L. Whitney	41	Corporate Secretary
Dr. Robert V. Antonucci	59	Director
David P. Brownell	61	Director
Michael J. Dalton	64	Director
Albert H. Elfner, III	60	Director
Ross B. George	72	Director
Edward F. Godfrey	55	Director
Michael B. Green	55	Director
Eben S. Moulton	58	Director
M. Brian O'Shaughnessy	63	Director
Charles H. Tenney, III	57	Director
Dr. Sarah P. Voll	62	Director

Robert G. Schoenberger has been Unitil's Chairman of the Board and Chief Executive Officer since 1997 and Unitil's President since 2003. Prior to his employment with Unitil, he was President and Chief Executive Officer of the New York Power Authority (a state owned public power enterprise) from 1993 until 1997. He is also a Trustee and Chairman of Exeter Health Resources.

Mark H. Collin was appointed Unitil's Senior Vice President and Chief Financial Officer in February 2003. Mr. Collin has served as Unitil's Treasurer since 1998. Since 1992, he has been Treasurer of UES and FG&E. Mr. Collin joined Unitil in 1988. Mr. Collin serves on the Board of Governors of New Hampshire Public Television.

Thomas P. Meissner, Jr. has been Unitil's Senior Vice President, Operations since February 2003. Mr. Meissner joined Unitil in 1994 and served as Unitil's Director of Engineering from 1998 to 2003. From 1985 to 1994, he was employed by the Public Service Company of New Hampshire.

George R. Gantz has been Unitil's Senior Vice President, Customer Services and Communications since January 2003. Mr. Gantz previously served as Unitil's Senior Vice President, Communication and Regulation from 1994 to 2003. Mr. Gantz joined Unitil in 1983.

George E. Long, Jr. has been Unitil's Vice President, Administration since February 2003. Mr. Long joined Unitil in 1994 and was Director, Human Resources from 1998 to 2003. Prior to his employment with Unitil, Mr. Long was the Director of Compensation and Benefits at Monarch Life Insurance Company from 1985 to 1994.

Raymond J. Morrissey has been Unitil's Vice President, Information Systems since February 2003. From 1992 to 2003, he served as Unitil's Vice President of Customer Service, and from 1991 to 1992, he was the General Manager of Unitil's subsidiary, FG&E. Mr. Morrissey joined Unitil in 1985.

Todd R. Black has been Unitil's Vice President, Energy Markets since January 2003. He served as Vice President, Sales and Marketing for Usource from 1998 to 2003. Prior to his employment with Unitil, he served as Vice President, Services Delivery for Energy USA, the unregulated subsidiary of Bay State Gas Company, from 1988 until 1998.

Laurence M. Brock, Unitil's Vice President and Controller, joined Unitil in 1995 and is a Certified Public Accountant in the State of New Hampshire. Prior to his employment with Unitil, Mr. Brock served as a Corporate Controller with a group of diversified financial services and manufacturing companies. Mr. Brock gained his public accounting experience with Coopers & Lybrand in Boston, Massachusetts.

David K. Foote has been Unitil's Vice President, Energy Contracts since 1984. Mr. Foote also serves as Senior Vice President of Unitil's subsidiary, FG&E, where he began working for the Company in 1968.

Sandra L. Whitney has been Unitil's Corporate Secretary and Secretary of the Board since February 2003. Ms. Whitney has been the Corporate Secretary of Unitil's subsidiary companies, FG&E, UES, Unitil Power, Unitil Realty and Unitil Service since 1994. Ms. Whitney joined Unitil in 1990.

Dr. Robert V. Antonucci has been President of Fitchburg State College since 2003. Dr. Antonucci was also President of the School Group of Riverdeep, Inc from 2001 to 2003, and President and CEO of Harcourt Learning Direct and Harcourt Online College from 1998 to 2001. Dr. Antonucci also served as the Commissioner of Education for the Commonwealth of Massachusetts from 1992-1998. Dr. Antonucci also serves as a Director of Plymouth Savings Bank and the Educational Lending Group.

David P. Brownell was a Senior Vice President of Tyco International Ltd. from 1995 to 2003. He had been with Tyco since 1984. Mr. Brownell is also Vice Chairman of the University of New Hampshire Foundation.

Michael J. Dalton was Unitil's President and Chief Operating Officer from 1984 to 2003. Mr. Dalton is a member of the Advisory Board of the University of New Hampshire College of Engineering and Physical Sciences.

Albert H. Elfner, III was the Chairman, from 1994, and Chief Executive Officer, from 1995, of Evergreen Investment Management Company until his retirement in 1999. Mr. Elfner is also a Director of NGM Insurance Company and Optimum Q Funds.

Ross B. George is the Chairman of the Board of Five G Management, LLC. He resigned as a Director of Simonds Industries, Inc. in August 2003 and served as their Chairman of the Board from 1999-2001 and their Chief Executive Officer from 1995 to 1999.

Edward F. Godfrey was the Executive Vice President and Chief Operating Officer of Keystone Investments, Incorporated from 1997 until his retirement in 1998. While at Keystone Investments, he was also a Senior Vice President, Chief Financial Officer and Treasurer from 1988 to 1996. Mr. Godfrey is also a Director of Reilly Mortgage Group and serves on their Audit Committee.

Michael B. Green has been the President and Chief Executive Officer of Capital Region Health Care and Concord Hospital since 1992. Mr. Green is also a member of the Adjunct Faculty, Dartmouth Medical School, Dartmouth College. He also currently Chairs the Foundation for Health Communities, is a Director of the Community Provider Network of Central New Hampshire, Director and Treasurer of the New Hampshire Hospital Association, Director of New Hampshire Business Committee for the Arts, Director of Merrimack County Savings Bank including membership on the bank's Investment and Audit Committees, and a member of the *Concord Monitor* Board of Contributors.

Eben S. Moulton has been the Managing Partner of Seacoast Capital Corporation since 1995. Mr. Moulton is also a Director of IEC Electronics, a Director of six private companies and a Trustee of Colorado College.

M. Brian O'Shaughnessy has been the Chairman of the Board, Chief Executive Officer and President of Revere Copper Products, Inc. since 1988. Mr. O'Shaughnessy also serves on the Board of Directors of the National Association of Manufacturers, the International Copper Association, the Copper Development Association, and the Copper and Brass Fabricators Council. He also serves in New York State as Chairman of the Industrial Energy Consumer Coalition, and as a member of the Board of Directors of the Multiple Intervenors.

Charles H. Tenney, III has been Director of Operations for Brainshift.com, Inc. since 2002. He also served as a financial advisor for H&R Block Financial Advisors from 2001 to 2002 and as the Director of Corporate Services for Log On America, Inc. from 1999 to 2000. Mr. Tenney also currently serves on the Board of Overseers of the Huntington Theater Company, Boston, MA.

Dr. Sarah P. Voll has been the Vice President, National Economic Research Associates, Inc. (NERA) since 1999. Dr. Voll was also a Senior Consultant at NERA from 1996 to 1999.

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled to be held at the offices of the Company, 6 Liberty Lane West, Hampton, New Hampshire, on Thursday, April 21, 2005, at 10:30 a.m.

Transfer Agent

The Company's transfer agent, EquiServe, is responsible for shareholder records, issuance of stock certificates, and the distribution of Unitil's dividends and IRS Form 1099-DIV. Shareholders may contact EquiServe at:

Mail: EquiServe, P.O. Box 43010, Providence, RI 02940-3010

Telephone: 800-736-3001 (Outside MA); 781-575-3100 (Within MA)

Investor Relations

For information about the Company and your investment, you may call the Company directly, toll-free, at: 800-999-6501 and ask for the Investor Relations Representative; visit the Investor page at *www.unitil.com*; or contact the transfer agent, EquiServe, at the number listed above.

Special Services & Shareholder Programs Available

- Internet Account Access is now available at *www.equiserve.com*.

- Dividend Reinvestment Plan:

  To enroll, please contact the Company's Investor Relations Representative at 800-999-6501.

- Dividend Direct Deposit Service:

  To enroll, please contact the Company's Investor Relations Representative at 800-999-6501.

- Direct Registration:

  For information, please contact EquiServe at the number listed above or the Company's Investor Relations Representative at 800-999-6501.

Item 2. Properties

As of December 31, 2004, Unitil owned, through its retail distribution utilities: two operation centers, approximately 2,135 pole miles of local transmission and distribution overhead electric lines and 391 conduit bank miles of underground electric distribution lines, along with 48 electric substations, including three mobile electric substations. FG&E's natural gas operations property includes a liquid propane gas plant, a liquid natural gas plant and 312 miles of underground gas mains. In addition, Unitil's real estate subsidiary, Unitil Realty, owns the Company's corporate office in Hampton, New Hampshire.

UES owns and maintains distribution operations centers in Concord, New Hampshire and Kensington, New Hampshire. UES' 31 electric distribution substations, including a 5,000 kilovolt ampere (kVA) mobile substation, constitute 226,937 kVA of capacity (includes spares and mobile) for the transformation of electric energy from the 34.5 kV subtransmission voltage to other primary distribution voltage levels. The electric substations are located on land owned by UES or occupied by UES pursuant to a perpetual easement.

UES has a total of approximately 1,582 pole miles of local transmission and distribution overhead electric lines and a total of 222 conduit bank miles of underground electric distribution lines. The electric distribution lines are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by UES without objection by the owners. In the case of certain distribution lines, UES owns only a part interest in the poles upon which its wires are installed, the remaining interest being owned by telephone companies.

Additionally, UES owns 137.7 acres of non-utility property located on the east bank of the Merrimack River in Concord, New Hampshire. Of the total acreage, 81.2 acres are located within an industrial park zone.

The physical utility properties of UES, with certain exceptions, and its franchises are pledged as security under its indenture of mortgage and deed of trust under which the respective series of first mortgage bonds of UES are outstanding.

FG&E's electric properties consist principally of 553 pole miles of local transmission and distribution overhead electric lines, 169 conduit bank miles of underground electric distribution lines and 17 transmission and distribution stations including two mobile electric substations. The capacity of these substations totals 562,650 kVA.

FG&E owns a liquid propane gas plant and a liquid natural gas plant and the land on which they are located. FG&E also has 312 miles of underground steel, cast iron and plastic gas mains.

FG&E's electric substations, with minor exceptions, are located on land owned by FG&E or occupied by FG&E pursuant to a perpetual easement. FG&E's electric distribution lines and gas mains are located in, on or under public highways or private lands pursuant to lease, easement, permit, municipal consent, tariff conditions, agreement or license, expressed or implied through use by FG&E without objection by the owners. FG&E leases its distribution operations center located in Fitchburg, Massachusetts.

Management believes that the Company's facilities are currently adequate for their intended uses.

Item 3. 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 Note 6 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 4. Submission of Matters to a Vote of Security Holders

None

PART II

Item 5. Market for Registrant's Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities

The Registrant's Common Stock is traded on the American Stock Exchange. As of December 31, 2004, there were 1,892 Common Shareholders of record.

Common Stock Data

Dividends per Common Share	2004	2003
1st Quarter	**$0.345**	$0.345
2nd Quarter	**0.345**	0.345
3rd Quarter	**0.345**	0.345
4th Quarter	**0.345**	0.345
Total for Year	**$ 1.38**	$ 1.38

	2004		2003	
Price Range of Common Stock	High/Ask	Low/Bid	High/Ask	Low/Bid
1st Quarter	**$27.72**	**$25.60**	$26.34	$23.31
2nd Quarter	**$28.25**	**$25.33**	$26.00	$22.92
3rd Quarter	**$27.24**	**$25.56**	$26.04	$24.17
4th Quarter	**$28.75**	**$27.08**	$26.00	$24.40

Information regarding Securities Authorized for Issuance Under Equity Compensation Plans is set forth in the table below.

EQUITY COMPENSATION PLAN BENEFIT INFORMATION

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders			
KESOP (1)	36,321	$12.51	29,101
Restricted Stock Plan (2)	—	N/A	156,200
Equity compensation plans not approved by security holders			
1998 Option Plan (3)	107,000	$27.13	—
Total	143,321	$23.43	185,301

NOTES: (also see Note 3 to the Consolidated Financial Statements)

(1) The KESOP was approved by shareholders in July 1989. Options were granted between January 1989 and November 1997.

(2) The Restricted Stock Plan was approved by shareholders in April 2003. 10,600 shares of restricted stock were awarded to Plan participants in May 2003; 10,700 shares of restricted stock were awarded to Plan participants in April 2004.

(3) The 1998 Option Plan was adopted by the Board of Directors of the Company in December 1998. At the time of adoption, the 1998 Option Plan was not required, under American Stock Exchange rules, to obtain shareholder approval. Options were granted in March 1999, January 2000, and January 2001. On January 16, 2003, the Board of Directors terminated the Option Plan upon the recommendation of the Compensation Committee. In April 2004, the 177,500 remaining registered and ungranted shares in the Option Plan were deregistered with the Securities and Exchange Commission. The Option Plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the Option Plan. No further grants of options will be made thereunder.

Unregistered Sales of Equity Securities and Uses of Proceeds

(a) There were no sales of unregistered equity securities by the Company for the fiscal period ended December 31, 2004.

(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)
10/1/04 – 10/31/04	—	—	—	n/a
11/1/04 – 11/30/04	108	$28.09	108	n/a
12/1/04 – 12/31/04	1,940	$28.34	1,940	n/a
Total	2,048	$28.33	2,048	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. Selected Financial Data

For the Years Ended December 31,	2004	2003	2002	2001	2000
(all data in thousands except % and per share data)					
Consolidated Statements of Earnings:					
Operating Revenue	**$ 214,137**	$ 220,654	$ 188,386	$ 207,022	$ 182,941
Operating Income	**15,193**	15,449	13,248	14,394	14,280
(Gain) Loss on Non-Utility Investments, net of tax	**—**	—	(82)	2,400	—
Other Non-operating Expense	**193**	(40)	185	170	244
Income Before Interest Expense and Extraordinary Item	**15,000**	15,489	13,145	11,824	14,036
Interest Expense, net	**6,774**	7,531	7,057	6,797	6,820
Income before Extraordinary Item	**8,226**	7,958	6,088	5,027	7,216
Extraordinary Item, net of tax	**—**	—	—	3,937	—
Net Income	**8,226**	7,958	6,088	1,090	7,216
Dividends on Preferred Stock	**215**	236	253	257	263
Earnings Applicable to Common Shareholders	**$ 8,011**	$ 7,722	$ 5,835	$ 833	$ 6,953
Balance Sheet Data:					
Utility Plant (Original Cost)	**$ 308,054**	$ 288,657	$ 272,402	$ 255,498	$ 238,023
Total Assets	**$ 457,010**	$ 483,877	$ 481,702	$ 376,762	$ 382,967
Capitalization:					
Common Stock Equity	**$ 94,291**	$ 92,805	$ 74,350	$ 74,746	$ 79,935
Preferred Stock	**2,338**	3,269	3,322	3,609	3,690
Long-Term Debt	**110,675**	110,961	104,226	107,470	81,695
Total Capitalization	**$ 207,304**	$ 207,035	$ 181,898	$ 185,825	$ 165,320
Short-term Debt	**$ 25,675**	$ 22,410	$ 35,990	$ 13,800	$ 32,500
Capital Structure Ratios:					
Common Stock Equity	**46%**	45%	41%	40%	48%
Preferred Stock	**1%**	2%	2%	2%	2%
Long-Term Debt	**53%**	53%	57%	58%	50%
Earnings Per Share Data:					
Earnings Per Average Share – Basic and Diluted	**$ 1.45**	$ 1.58	$ 1.23	$ 0.18	$ 1.47
Common Stock Data:					
Shares of Common Stock – Diluted (Average)	**5,525**	4,896	4,762	4,760	4,743
Dividends Paid Per Share	**$ 1.38**	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Book Value Per Share (Year-End)	**$ 17.00**	$ 16.87	$ 15.67	$ 15.76	$ 16.88
Electric and Gas Sales:					
Electric Distribution Sales (kWh)	**1,742,131**	1,717,664	1,659,136	1,596,390	1,587,536
Firm Natural Gas Distribution Sales (Therms)	**23,151**	24,592	22,480	23,067	23,992

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (Note references are to Notes to the Consolidated Financial Statements in Item 8.)

Forward-Looking Information

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.

EARNINGS & DIVIDENDS

The Company's Earnings were $8.0 million for 2004, an increase of $0.3 million, or 3.7%, compared to 2003. Earnings per common share were $1.45 for 2004 compared with earnings of $1.58 per share for 2003 and $1.43, before the effect of a restructuring charge, for 2002. The Earnings per share figures reflect approximately 13% more shares outstanding in 2004 than in 2003, due to the Company's public offering in the fourth quarter of 2003.

Unitil's annual common dividend was $1.38. At its January, 2005 meeting, the Unitil Board of Directors declared a quarterly dividend on the Company's common stock of $0.345 per share, reflecting the Company's unbroken record of paying a regular quarterly dividend.

Earnings & Dividends Data	2004	2003	2002
Earnings per Share Before Other Items **(non-GAAP)**	**$1.45**	$1.58	$ 1.43
Other Item, net of tax:			
Restructuring Charge	**—**	—	(0.20)
Earnings per Share	**$1.45**	$1.58	$ 1.23
Annual Dividend Rate	**$1.38**	$1.38	$ 1.38

The presentation of earnings per share data in the table above includes a line item identified as “Earnings per Share Before Other Items.” Though this measurement is based on Generally Accepted Accounting Principles (GAAP) consistently applied, the measurement itself is not specifically defined under GAAP and is therefore required to be presented as a non-GAAP measure. “Earnings per Share Before Other Items” is a non-GAAP measure and may not be comparable to other non-GAAP measures of earnings per share used by other companies. Management believes this measure is useful to investors because it includes the same company-specific information that is used by Management to assess the Company’s financial performance.

In 2002, Unitil recorded a Restructuring Charge of $1.6 million before taxes, or ($0.20) per share, related to the elimination of 19 management and administrative positions.

A more detailed discussion of the Company’s 2004 Results of Operations and a year-to-year comparison of changes in financial position for the three-year period 2002 through 2004 are presented below.

RESULTS OF OPERATIONS

Operating Revenue—Electric

Electric Operating Revenue—Electric Operating Revenue, decreased by $7.0 million, or 3.7%, in 2004 as compared to 2003. 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 primarily reflects lower Purchased Electricity costs compared to the prior period. The Purchased Electricity cost of sales component decreased $8.1 million, or 6.0%, in 2004 as compared to 2003, 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 decreased $0.1 million, or 3.2% in 2004 as compared to 2003. 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 $54.4 million in 2004. This represents an increase of $1.2 million compared to 2003. This increase reflects increased kWh sales to both residential and commercial and industrial customer classes.

In 2003, Electric Operating Revenue increased by $23.5 million, or 14.1% compared to 2002. The Purchased Electricity cost of sales component increased $16.8 million in 2003 compared to 2002. Approximately 75% of this increase reflects higher electric commodity prices while the remainder reflects an increase of 3.5% in electric unit sales volume. Electric sales margin was $53.2 million in 2003, an increase of $4.8 million over 2002. Approximately 65% of this increase reflects the impact of 2002 base rate cases, which resulted in higher base distribution rates for the Company’s electric retail distribution utilities as of December 2002. The remainder of the increase in electric sales margin is due to a 3.5% increase in electric unit sales in 2003 compared to 2002.

The following table details total Electric Operating Revenue and Sales Margin for the last three years by major customer class:

Electric Operating Revenue and Sales Margin (000's)

	2004	2003	2002	% Change 2004 vs. 2003	% Change 2003 vs. 2002
Electric Operating Revenue:					
Residential	**$ 75,689**	$ 76,893	$ 65,746	(1.6%)	17.0%
Commercial/Industrial	**108,200**	113,971	101,571	(5.1%)	12.2%
Total Electric Operating Revenue	**$183,889**	$190,864	$167,317	(3.7%)	14.1%
Cost of Sales:					
Purchased Electricity	**$125,940**	$134,036	$117,282	(6.0%)	14.3%
Conservation & Load Management	**3,527**	3,643	1,603	(3.2%)	127.3%
Gross Electric Sales Margin	**$ 54,422**	$ 53,185	$ 48,432	2.3%	9.8%

Kilowatt-hour Sales—Unitil's total electric kilowatt-hour (kWh) sales increased 1.4% in 2004 compared to 2003. This increase reflects growth in sales to residential and commercial and industrial customer classes driven by a consistent customer growth year over year.

Sales to residential customers increased 1.1% in 2004 compared to 2003, despite 33% cooler summer weather in 2004 compared to 2003 which negatively affected kWh sales for air conditioning and other cooling purposes in 2004. The increase in energy sales reflects an increase in the number of residential customers. Commercial and industrial sales of electricity increased 1.6% in 2004 compared to 2003, reflecting an increase in the number of customers as well as higher average usage.

Unitil's total electric kilowatt-hour (kWh) sales increased by 3.5% in 2003 compared to 2002. This increase reflected growth in sales to residential and commercial and industrial customer classes driven by a colder winter heating season and steady customer growth year over year.

The following table details total kWh sales for the last three years by major customer class:

kWh Sales (000's)

	2004	2003	2002	% Change 2004 vs. 2003	% Change 2003 vs. 2002
Residential	**652,763**	645,711	619,756	1.1%	4.2%
Commercial/Industrial	**1,089,368**	1,071,953	1,039,380	1.6%	3.1%
Total	**1,742,131**	1,717,664	1,659,136	1.4%	3.5%

Operating Revenue—Gas

Gas Operating Revenue—Gas Operating Revenue increased $0.1 million, or 0.3%, in 2004 compared to 2003. 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 $0.1 million, or 0.4%, in 2004 compared to 2003. 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 increased $0.2 million in 2004 compared to 2003. 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 $10.7 million in 2004. This represents a decrease of $0.2 million compared to 2003. Total firm therm unit sales decreased 5.9% in 2004 compared to 2003 reflecting milder winter weather in 2004 compared to 2003.

Gas sales margin was $10.9 million in 2003, an increase of $3.1 million over 2002. Approximately 76% of this increase reflects the impact of 2002 base rate cases, which resulted in higher base distribution rates for the Company's natural gas retail distribution utility as of December 2002. The remainder of the increase in natural gas sales margin is due to higher unit sales in 2003 compared to 2002.

The following table details total Gas Operating Revenue and Margin for the last three years by major customer class:

Gas Operating Revenue and Sales Margin (000's)

				% Change	
	2004	**2003**	**2002**	**2004 vs. 2003**	**2003 vs. 2002**
Gas Operating Revenue:					
Residential	**$16,313**	$16,267	$10,871	0.3%	49.6%
Commercial/Industrial	**12,323**	11,979	8,007	2.9%	49.6%
Total Firm Gas Revenue	**$28,636**	$28,246	$18,878	1.4%	49.6%
Interruptible Gas Revenue	**49**	366	1,405	(86.6%)	(74.0%)
Total Gas Operating Revenue	**$28,685**	$28,612	$20,283	0.3%	41.1%
Cost of Sales:					
Purchased Gas	**$17,486**	$17,421	$12,304	0.4%	41.6%
Conservation & Load Management	**476**	287	168	66.0%	70.5%
Gross Gas Sales Margin	**$10,723**	$10,904	$ 7,811	(1.7%)	39.6%

Therm Sales—Unitil's total firm therm sales of natural gas decreased 5.9% in 2004 compared to 2003, due to a milder winter heating season in early 2004 and lower natural gas usage by our largest customers year over year. Sales to residential customers decreased 7.1% and sales to commercial and industrial customers decreased 4.7% in 2004 compared to 2003.

In 2003, total firm therm sales increased 9.4% compared to 2002, primarily due to a colder winter heating season in early 2003.

The following table details total firm therm sales for the last three years, by major customer class:

Firm Therm Sales (000's)

				% Change	
	2004	**2003**	**2002**	**2004 vs. 2003**	**2003 vs. 2002**
Residential	**11,319**	12,181	11,022	(7.1%)	10.5%
Commercial/Industrial	**11,832**	12,411	11,458	(4.7%)	8.3%
Total	**23,151**	24,592	22,480	(5.9%)	9.4%

Operating Revenue—Other

Total Other Revenue increased $0.4 million, including a 36% increase in revenue from the Company's energy brokering business, Usource, in 2004 compared to 2003. Total Other Revenue increased $0.4 million in 2003 compared to 2002, including an increase of 51.9% in revenue from Usource.

The following table details total Other Revenue for the last three years:

Other Revenue (000's)

	2004	2003	2002	% Change 2004 vs. 2003	% Change 2003 vs. 2002
Usource	**$1,563**	$1,148	$756	36.1%	51.9%
Other	**—**	30	30	—	—
Total Other Revenue	**$1,563**	$1,178	$786	32.7%	49.9%

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 $8.1 million in 2004 compared to 2003, reflecting lower electric commodity prices. The Company recovers the costs of Purchased Electricity in its rates at cost and therefore changes in these expenses do not affect earnings.

In 2003, Purchased Electricity expenses increased $16.8 million, or 14.3%, compared to 2002. Approximately 75% of this increase reflects higher electric commodity prices while the remainder reflects an increase of 3.5% in electric unit sales volume.

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 $0.1 million, or 0.4%, in 2004 compared to 2003. 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.

In 2003, Purchased Gas increased by $5.1 million, or 41.6%, compared to 2002. Approximately 77% of this increase reflects higher gas commodity prices while the remainder reflects an increase of 9.4% in gas unit sales during the period.

Operation and Maintenance (O&M)—O&M expense includes electric and gas utility operating costs, and the operating cost of the Company's unregulated business activities. Total O&M expense increased $0.6 million, or 2.6%, in 2004 compared to 2003.

This increase reflects higher compensation expenses ($0.6 million), employee benefit costs ($0.6 million) and higher audit, regulatory and professional fees ($0.2 million) incurred in 2004. The higher audit, regulatory and professional fee expenses include expenditures to third parties incurred by the Company for its efforts in complying with Section 404 of the Sarbanes-Oxley Act of 2002 (SOXA), which required a comprehensive review, documentation and testing of the Company's internal controls over financial reporting. In addition to these amounts, a significant effort was expended internally by Company resources to complete the SOXA project. The increases discussed above were partially offset by lower utility operating and maintenance costs, $0.5 million and other expenses, net of $0.3 million.

In 2003, total O&M expense increased $2.7 million, or 13.2%, compared to 2002, primarily reflecting higher compensation, employee benefits and insurance costs over the prior year.

Conservation & Load Management—Conservation and Load Management expenses are expenses associated with the development, management, and delivery of the Company's energy efficiency programs. Energy Efficiency programs are designed, in conformity to 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 Conservation & Load Management expenses increased $0.1 million, or 1.9%, in 2004 compared to 2003. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs do not affect on earnings.

Total Conservation & Load Management expenses increased $2.1 million, or 121.9%, in 2003 compared to 2002 reflecting several new Energy Efficiency programs that were implemented during the year.

Depreciation, Amortization and Taxes

Depreciation and Amortization—Depreciation and Amortization expense increased $0.1 million, or 0.4%, in 2004 compared to 2003, due to the increased investment in utility plant additions partially offset by lower amortization in 2004 on intangible assets.

In 2003, Depreciation and Amortization expense increased $3.8 million, or 25.8%, compared to 2002, due mainly to higher utility depreciation rates, which were included as a component of the new rates implemented by our retail distribution utilities in December 2002, together with an increased investment in utility plant additions, partially offset by the amortization of intangible assets, ($0.6 million) in 2003 which were fully amortized by December 31, 2003.

Local Property and Other Taxes—Local Property and Other Taxes increased $0.4 million, or 7.8%, in 2004 compared to 2003 and by $0.1 million, or 1.6%, in 2003 compared to 2002. These increases were related to higher levels of utility plant in service.

Federal and State Income Taxes—Federal and State Income Taxes increased $0.7 million, or 18.4%, in 2004 compared to 2003, and by $1.1 million, or 42.8%, in 2003 compared to 2002. These increases were related to higher pre-tax operating income year over year.

Interest Expense, net

Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and 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 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. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (000's)	2004	2003	2002
Interest Expense			
Long-term Debt	**$ 8,492**	$ 8,170	$ 8,336
Short-term Debt	**629**	1,071	1,037
Subtotal Interest Expense	**9,121**	9,241	9,373
Interest Income			
Regulatory Assets	**(2,310)**	(1,657)	(2,090)
AFUDC and Other	**(16)**	(46)	(52)
Other	**(21)**	(7)	(174)
Subtotal Interest Income	**(2,347)**	(1,710)	(2,316)
Total Interest Expense, net	**$ 6,774**	$ 7,531	$ 7,057

In 2004, Interest Expense, net, declined by approximately $0.8 million compared to 2003. The reduction in Interest Expense, net, is mainly due to the increase in interest income of $0.7 million during 2004, principally related to carrying charges applicable to higher levels of regulatory assets. In addition, interest expense on short-term debt decreased $0.4 million due to lower levels of average short-term borrowings outstanding. These gains were partially offset by increased interest expense on long-term debt of $0.3 million.

In 2003, Interest Expense, net, increased by $0.5 million over 2002. This increase was driven by lower interest income on regulatory assets, which decreased $0.4 million in 2003 compared with 2002 due mainly to lower carrying charges applicable to regulatory asset balances. In addition, interest expense declined $0.1 million compared with 2002, reflecting lower interest on long-term debt.

2002 Restructuring Charge—In the fourth quarter of 2002, the Company recognized a pre-tax Restructuring Charge of $1.6 million. The after-tax effect of the Restructuring Charge was a reduction of $0.20 in Earnings Per Common Share, assuming full dilution.

In December 2002, the Company undertook a strategic review of its business operations and committed to a formal transition and reorganization plan (the Reorganization Plan) to streamline its management structure, in order to improve operating efficiency and to align the organization to meet ongoing business requirements. The Reorganization Plan resulted in the elimination of 19 management and administrative positions.

Capital Requirements and Liquidity

Unitil requires capital to fund utility plant additions, working capital and other utility expenditures recovered in subsequent and future periods through regulated rates. The capital necessary to meet these requirements is derived primarily from internally-generated funds, which consist of cash flows from operating activities, excluding payment of dividends. The Company supplements internally generated funds through bank borrowings, as needed, under unsecured short-term bank lines. At December 31, 2004, Unitil had an aggregate of $33.0 million in unsecured revolving lines of credit with three banks. The Company anticipates that it will be able to secure renewal or replacement of some or all of its revolving lines of credit, in accordance with projected requirements. Average short-term borrowings against the lines of credit in 2004 were $18.0 million, a decrease of $15.4 million over the average short-term debt outstanding in 2003. Periodically, the Company replaces portions of its short-term debt with long-term financings more closely matched to the long-term lives of its utility assets.

The maximum amount of short-term borrowings that may be incurred by Unitil and its subsidiaries is subject to periodic approval by the SEC under the Public Utility Holding Company Act of 1935 and state regulators of the Company’s retail distribution utilities, UES and FG&E. At December 31, 2004, Unitil had regulatory authorization to incur total short-term bank borrowings up to a maximum of $55 million, and UES and FG&E had regulatory authorizations to borrow up to a maximum of $16 million and $35 million, respectively. In 2004, UES and FG&E had average short-term debt outstanding of $3.8 million and $19.5 million, respectively. At December 31, 2004, UES and FG&E had short-term debt outstanding of approximately $3.8 million and $25.8 million, respectively.

Unitil and its subsidiaries are individually and collectively members of the Unitil Cash Pool. The Cash Pool is the financing vehicle for day-to-day cash borrowing and investing. The Cash Pool Agreement allows an efficient exchange of cash among Unitil and its subsidiaries. The Cash Pool Agreement and its transactions are monitored by the SEC under PUHCA. The interest rates charged to the subsidiaries for borrowing from the Cash Pool are based on Unitil’s actual interest costs from its banks under the revolving lines of credit. In addition, Unitil is required by the SEC to maintain a minimum 30% common equity ratio, including short-term debt, in order to utilize the Cash Pool. At December 31, 2004, all Unitil subsidiaries were in compliance with the requirements to participate in the Cash Pool.

In 2003, the Company completed two long-term financings in the form of Unitil Corporation Common Stock and FG&E Long-term Notes. The Common Stock offering provided net proceeds of $16.9 million which were used to make capital contributions of $6.0 million to each of the retail distribution utilities (see Note 3) and for general corporate purposes. FG&E issued $10.0 million in Long-term Notes under a debenture note structure (see Note 4). The Company expects to continue to be able to satisfy its external financing needs by utilizing additional short-term bank borrowings and to periodically replace short-term debt with long-term financings. The continued availability of these methods of financing, as well as the Company's choice of a specific form of security, will depend on many factors, including: security market conditions; general economic climate; regulatory approvals; the ability to meet covenant issuance restrictions, if any; the level of the Company's earnings, cash flows and financial position; and the competitive pricing offered by financing sources.

In 2004 and 2003, the Company and its subsidiaries made cash contributions to their pension plans in the amounts of $2.0 million and $1.2 million, respectively. The Company may elect to fund the pension plan in future periods. In January 2004, Unitil established Voluntary Employee Benefit Trusts (VEBT) to provide post-retirement benefits. In 2004, the Company and its subsidiaries contributed approximately $2.4 million to the VEBT and expects to continue to make contributions to the VEBT in future years in amounts consistent with the amounts recovered in retail distribution utility rates for these benefit costs. Prior to the establishment of the VEBT, post-retirement benefits for employees of the Company and its subsidiaries were funded through contributions to the Unitil Retiree Trust (URT). (See Note 9).

Off-Balance Sheet Arrangements

The Company does not currently use, and is not dependent on the use of off-balance sheet financing arrangements, such as securitization of receivables, or obtaining access to assets or cash through special purpose entities or variable interest entities.

Contractual Obligations

The table below lists the Company's significant contractual obligations as of December 31, 2004.

		Payments Due by Period			
Significant Contractual Obligations (000's) as of December 31, 2004	**Total**	**2005**	**2006-2007**	**2008-2009**	**2010 & Beyond**
Long-term Debt	$110,960	$ 286	$ 646	$ 758	$109,270
Capital Lease	646	440	181	21	4
Operating Leases	2,182	270	540	540	832
Power Supply Contract Obligations—MA	65,724	7,833	15,905	16,396	25,590
Power Supply Contract Obligations—NH	74,724	17,722	25,760	21,764	9,478
Gas Supply Contracts	14,217	10,876	3,046	295	—
Total Contractual Cash Obligations	$268,453	$37,427	$46,078	$39,774	$145,174

The Company does have material energy supply commitments that are discussed in Note 5. Cash outlays for the purchase of electricity and natural gas to serve our customers are subject to full recovery through periodic changes in rates, with carrying charges on deferred balances. From year to year, there are likely to be timing differences associated with the cash recovery of such costs, creating under- or over-recovery situations at any point in time. Rate recovery mechanisms are typically designed to collect the under-recovered cash or refund the over collected cash over subsequent 6-12 month periods.

The Company also provides limited guarantees on certain electric supply contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2004 there are $1.0 million of guarantees outstanding and these guarantees extend through October 14, 2006.

Financial Covenants and Restrictions

The agreements under which the long-term debt of the retail distribution utilities, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The Indenture Agreements further require that if UES defaults on any FMB securities, it would constitute a default for all UES FMB securities. The default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the Indenture Agreements, FG&E agreements require that if FG&E defaults on any long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of Unitil or its other subsidiaries.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

In addition, the UES and FG&E long-term debt instruments and agreements contain certain restrictions on the payment of common dividends from Retained Earnings. On December 31, 2004, UES and FG&E had unrestricted Retained Earnings of $12,514,000 and $6,696,000, respectively, available for the payment of common dividends. (See Note 3). UES and FG&E pay dividends to their sole shareholder, Unitil Corporation, and these dividends are the primary source of cash for the payment of dividends to Unitil shareholders.

Unitil Corporation has no long-term debt outstanding. The long-term debt and preferred stock of UES and FG&E are privately held, and the Company does not issue commercial paper. For these reasons, these securities of Unitil and its subsidiaries are not publicly rated.

Results of Operations—Cash Flows

Cash Provided by Operating Activities—Cash flows from operating activities of $30.6 million increased by $15.0 million in 2004 compared to 2003. This increase is due to changes in the Company's working capital requirements. Sources of cash from Accrued Revenues increased $7.1 million, principally due to the recovery of 2003 deferred energy costs. In addition, sources of cash from Prepayments and Other increased $8.8 million in 2004 compared to 2003, primarily related to prepayments to wholesale electricity suppliers made in 2003 that were applied in 2004. All other changes in cash flows from operating activities were a net increase of ($0.8 million) in uses of cash in 2004 compared to 2003.

Cash flows from operating activities increased $6.1 million in 2003 over 2002. This increase was attributable to higher earnings in 2003 and increased sources of cash from working capital which were primarily driven by new, higher retail utility service rates implemented by the Company in December, 2002, partially offset by the funding of prepaid wholesale electricity costs in the fourth quarter of 2003.

	2004	2003	2002
Cash Provided by Operating Activities (000's)	**$30,648**	$15,621	$9,568

Cash (Used in) Investing Activities—Cash flows used in investing activities increased by $1.0 million in 2004 compared to 2003, and by $2.6 million in 2003 compared to 2002. Cash used in investing activities is primarily for capital expenditures related to electric and gas distribution system additions. In 2002, the Company also received $1.5 million of proceeds from the sale of its ownership interest in a non-utility investment. Capital expenditures are projected to be $26.4 million in 2005, reflecting normal electric and gas utility system additions including $2.4 million for the initial phase of the Automated Meter Reading project.

	2004	2003	2002
Cash Used in Investing Activities (000's)	**$(22,922)**	$(21,939)	$(19,290)

Cash Provided by (Used in) Financing Activities—Cash used in financing activities was $8.5 million in 2004. In 2004, cash sources from increasing short-term debt by $3.3 million were offset by cash uses of $3.3 million to repay long-term debt, resulting in no net increase in total debt outstanding. In addition, the Company paid $7.9 million in common and preferred dividends in 2004 and redeemed Preferred Stock for $0.9 million.

Cash provided by financing activities in 2003 was $2.9 million, reflecting financing proceeds of $27.7 million from the issuance of common stock equity and new long term debt, which was partially offset by the repayment of short-term borrowings of $13.6 million and long term debt sinking fund payments of $3.2 million.

On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares).

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%.

	2004	2003	2002
Cash Provided by (Used in) Financing Activities (000's)	**$(8,460)**	$2,924	$10,806

Dividends

Unitil's annualized common dividend was $1.38 per common share in 2004, 2003 and 2002. Unitil's dividend policy is reviewed annually by the Board of Directors. The amount and timing of all dividend payments are subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors.

Interest Rate Risk

As discussed above, Unitil meets its external financing needs by issuing short-term and long-term debt. The majority of 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 issuances of long-term debt securities. In addition, short-term debt borrowings bear a variable rate of interest. As a result, changes in short-term interest rates will increase or decrease interest expense in future periods. For example, if the 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. The average interest rate on short-term borrowings was 1.9%, 1.8% and 2.2% during 2004, 2003 and 2002, 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 electric power and natural gas supply 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, 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 Massachusett's 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 $176 million as of December 31, 2004 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 has also 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. FG&E was required to provide Standard Offer through February 2005 at rate levels which provide state-mandated rate reductions. New distribution customers and customers no longer eligible for Standard Offer were eligible to receive Default Service at prices set periodically based on market solicitations as approved by the MDTE. As of December 31, 2004, competitive suppliers were serving approximately 36 percent of FG&E's electric load, primarily for FG&E's largest customers. On March 1, 2005, customers on Standard Offer will be automatically placed on Default Service.

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 ends 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 has advised the MDTE that it will file a proposed plan for recovery of these deferred amounts beginning March 1, 2005. The value of FG&E's generation-related and deferred-cost Regulatory Assets was approximately $35.0 million at December 31, 2004, and $31.7 million at December 31, 2003, and is expected to be recovered in FG&E's rates over the next 6 to 8 years. In addition, as of December 31, 2004, FG&E had recorded on its balance sheets $65.7 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—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 December 31, 2004, FG&E has recorded a regulatory asset of $1.6 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 December 31, 2004, UES had recorded on its balance sheets $74.7 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 7 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 (E&H and CECo were UES' predecessor companies). The NHPUC approved this filing, effective May 1, 2004.

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 allow deferral of its pension expenses above the level recovered in base rates of $0.6 million for 2004 until UES files its next base rate case which will be filed no later than October, 2007. This matter remains pending.

Effective as of 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 provides that it will terminate when all costs have been collected.

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.

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. FGE and UES have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. 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. 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.

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.

Former Electric Generating Station—In 2003, FG&E completed environmental remediation action to abate and remove asbestos-containing and other hazardous materials at a former electric generating station located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware. FG&E received significant coverage from its insurance carrier for this remediation project and the resolution of this matter did not have a material adverse effect on the Company's financial position.

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 judgment; 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 by the retail distribution companies: UES and FG&E. Both UES and FG&E are subject to regulation by the FERC and FG&E is regulated by the MDTE and UES is regulated by the NHPUC. Accordingly, the Company uses the provisions of 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 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 and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

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

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

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

Pension and Postretirement Benefit Obligations—The Company has a defined benefit pension plan covering substantially all its employees and also provides certain other post-retirement benefits (PBOP), primarily medical and life insurance benefits to retired employees. The Company also has a Supplemental Executive Retirement Plan (SERP) covering certain executives of the Company. The Company accounts for these benefits in 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. See Note 9.

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

The discount rate that is utilized in determining future pension obligations is based on a basket of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. For 2004, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2002 and 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $50,000 and $150,000, respectively. The effect of a change in discount rates for 2003 and 2004 would have been greater than for 2002 because of the significant market declines that affected 2003 and 2004 pension costs. The compensation increase assumptions used for 2002, 2003 and 2004 were 4.00%, 4.00% and 3.50%, respectively, based on the expected increase in payroll for personnel covered by the Plan.

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts. See Note 8.

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. 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. As of December 31, 2004, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

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

For further information regarding these types of activities, see Note 1, "Summary of Significant Accounting Policies," Note 8, "Income Taxes," Note 5, "Energy Supply," Note 9, "Benefit Plans," and Note 6, "Commitment and Contingencies," to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Reference is made to the "Interest Rate Risk" and "Market Risk" sections of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" (above).

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Unitil Corporation and subsidiaries as of December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Boston, Massachusetts
February 17, 2005

Report of Independent Registered Public Accounting Firm

To the Shareholders of Unitil Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that Unitil Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Unitil Corporation and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control-Integrated Framework issued by the COSO. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in the Internal Control-Integrated Framework issued by the COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and consolidated statements of capitalization of Unitil Corporation and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of earnings, cash flows and changes in common stock equity for each of the three years in the period ended December 31, 2004 and our report dated February 17, 2005, expressed an unqualified opinion on those consolidated financial statements.

/s/ GRANT THORNTON LLP

Boston, Massachusetts
February 17, 2005

CONSOLIDATED STATEMENTS OF EARNINGS

(000's, except common shares and per share data)

Year Ended December 31,	**2004**	**2003**	**2002**
Operating Revenues:			
Electric	**$ 183,889**	$ 190,864	$ 167,317
Gas	**28,685**	28,612	20,283
Other	**1,563**	1,178	786
Total Operating Revenues	**214,137**	220,654	188,386
Operating Expenses:			
Purchased Electricity	**125,940**	134,036	117,282
Purchased Gas	**17,486**	17,421	12,304
Operation and Maintenance	**23,297**	22,706	20,051
Conservation & Load Management	**4,003**	3,930	1,771
Restructuring Charge	**—**	—	1,598
Depreciation and Amortization	**18,830**	18,756	14,911
Provisions for Taxes:			
Local Property and Other	**5,182**	4,805	4,731
Federal and State Income	**4,206**	3,551	2,490
Total Operating Expenses	**198,944**	205,205	175,138
Operating Income	**15,193**	15,449	13,248
Sale of Non-Utility Investments, net of tax	**—**	—	(82)
Other Non-Operating Expenses (Income)	**193**	(40)	185
Income Before Interest Expense	**15,000**	15,489	13,145
Interest Expense, net	**6,774**	7,531	7,057
Net Income	**8,226**	7,958	6,088
Less Dividends on Preferred Stock	**215**	236	253
Earnings Applicable to Common Shareholders	**$ 8,011**	$ 7,722	$ 5,835
Average Common Shares Outstanding—Basic	**5,509,321**	4,877,933	4,743,696
Average Common Shares Outstanding—Diluted	**5,524,835**	4,896,329	4,762,166
Earnings per Common Share—Basic and Diluted	**$ 1.45**	$ 1.58	$ 1.23

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

CONSOLIDATED BALANCE SHEETS (000'S)

ASSETS

December 31,	2004	2003
Utility Plant:		
Electric	**$222,121**	$209,288
Gas	**53,208**	48,700
Common	**28,271**	27,441
Construction Work in Progress	**4,454**	3,228
Utility Plant	**308,054**	288,657
Less: Accumulated Depreciation	**104,051**	93,592
Net Utility Plant	**204,003**	195,065
Current Assets:		
Cash	**3,032**	3,766
Accounts Receivable—(Net of Allowance for Doubtful Accounts of $501 and $541)	**18,119**	17,461
Accrued Revenue	**9,754**	10,029
Refundable Taxes	**977**	3,816
Material and Supplies	**3,080**	2,861
Prepayments and Other	**1,771**	6,146
Total Current Assets	**36,733**	44,079
Noncurrent Assets:		
Regulatory Assets	**199,608**	227,528
Prepaid Pension	**10,990**	10,972
Debt Issuance Costs, net	**2,265**	1,844
Other Noncurrent Assets	**3,411**	4,389
Total Noncurrent Assets	**216,274**	244,733
TOTAL	**$457,010**	$483,877

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

CONSOLIDATED BALANCE SHEETS (cont.) (000'S)

CAPITALIZATION AND LIABILITIES

December 31,	2004	2003
Capitalization:		
Common Stock Equity	**$ 94,291**	$ 92,805
Preferred Stock, Non-Redeemable, Non-Cumulative	**225**	225
Preferred Stock, Redeemable, Cumulative	**2,113**	3,044
Long-Term Debt, Less Current Portion	**110,675**	110,961
Total Capitalization	**207,304**	207,035
Current Liabilities:		
Long-Term Debt, Current Portion	**285**	3,263
Capitalized Leases, Current Portion	**413**	567
Accounts Payable	**16,249**	15,024
Short-Term Debt	**25,675**	22,410
Dividends Declared and Payable	**50**	70
Refundable Customer Deposits	**1,545**	1,429
Interest Payable	**1,328**	1,356
Other Current Liabilities	**5,607**	4,254
Total Current Liabilities	**51,152**	48,373
Deferred Income Taxes	**56,156**	56,900
Noncurrent Liabilities:		
Power Supply Contract Obligations	**140,448**	167,341
Capitalized Leases, Less Current Portion	**183**	403
Other Noncurrent Liabilities	**1,767**	3,825
Total Noncurrent Liabilities	**142,398**	171,569
TOTAL	**$457,010**	$483,877

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(000's except number of shares and par value)

December 31,	2004	2003
Common Stock Equity		
Common Stock, No Par Value (Authorized—8,000,000 shares; Outstanding—5,546,620 and 5,500,610 shares)	**$ 59,795**	$ 58,848
Stock Compensation Plans	**1,059**	908
Retained Earnings	**33,437**	33,049
Total Common Stock Equity	**94,291**	92,805
Preferred Stock		
UES Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**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
8.00% Series, $100 Par Value	**1,214**	1,218
Total Preferred Stock	**2,338**	3,269
Long-Term Debt		
UES First Mortgage Bonds:		
8.49% Series, Due October 14, 2024	**15,000**	15,000
6.96% Series, Due September 1, 2028	**20,000**	20,000
8.00% Series, Due May 1, 2031	**15,000**	15,000
FG&E Long-Term Notes:		
8.55% Notes, Due March 31, 2004	**—**	3,000
6.75% Notes, Due November 30, 2023	**19,000**	19,000
7.37% Notes, Due January 15, 2029	**12,000**	12,000
7.98% Notes, Due June 1, 2031	**14,000**	14,000
6.79% Notes, Due October 15, 2025	**10,000**	10,000
Unitil Realty Corp. Senior Secured Notes:		
8.00% Notes, Due August 1, 2017	**5,960**	6,224
Total Long-Term Debt	**110,960**	114,224
Less: Long-Term Debt, Current Portion	**285**	3,263
Total Long-Term Debt, Less Current Portion	**110,675**	110,961
Total Capitalization	**$207,304**	$207,035

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

CONSOLIDATED STATEMENTS OF CASH FLOWS (000's)

Year Ended December 31,	2004	2003	2002
Operating Activities:			
Net Income	**$ 8,226**	$ 7,958	$ 6,088
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**18,830**	18,756	14,911
Deferred Tax Provision	**3,166**	6,375	856
Gain on Sale of Investments, net	**—**	—	(82)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**(658)**	2,052	(2,380)
Accrued Revenue	**275**	(6,795)	(3,512)
Refundable Taxes	**2,839**	1,035	(2,419)
Materials and Supplies	**(219)**	(538)	481
Prepayments and Other	**4,375**	(4,411)	154
Accounts Payable	**1,225**	803	(5,863)
Refundable Customer Deposits	**116**	93	(57)
Interest Payable	**(28)**	45	(64)
Other Current Liabilities	**1,353**	(4,808)	2,734
Deferred Restructuring Charges	**(5,900)**	(6,058)	(4,523)
Other, net	**(2,952)**	1,114	3,244
Cash Provided by Operating Activities	**30,648**	15,621	9,568
Investing Activities:			
Property, Plant and Equipment Additions	**(22,922)**	(21,939)	(20,825)
Proceeds from the Sale of Investments	**—**	—	1,535
Cash Used In Investing Activities	**(22,922)**	(21,939)	(19,290)
Financing Activities:			
Proceeds from (Repayment of) Short-Term Debt	**3,265**	(13,580)	22,190
Issuance of Long-Term Debt	**—**	10,000	—
Repayment of Long-Term Debt	**(3,264)**	(3,244)	(3,225)
Retirement of Preferred Stock	**(931)**	(53)	(293)
Dividends Paid	**(7,857)**	(7,056)	(6,831)
Issuance of Common Stock	**947**	17,628	—
Repayment of Capital Lease Obligations	**(620)**	(771)	(1,035)
Cash Provided by (Used In) Financing Activities	**(8,460)**	2,924	10,806
Net Increase (Decrease) in Cash	**(734)**	(3,394)	1,084
Cash at Beginning of Year	**3,766**	7,160	6,076
Cash at End of Year	**$ 3,032**	$ 3,766	$ 7,160
Supplemental Information:			
Interest Paid	**$ 9,052**	$ 9,113	$ 9,356
Income Taxes Paid (Refunded)	**$ 990**	$ (2,541)	$ 2,351
Supplemental Schedule of Noncash Activities:			
Capital Leases Incurred	**$ 246**	$ 109	$ 436

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

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY

(000's except number of shares)

	Common Shares	Stock Compensation Plans	Retained Earnings	Total
Balance at January 1, 2002	$41,220	$ 669	$32,857	**$74,746**
Net Income for 2002			6,088	**6,088**
Dividends on Preferred Shares			(253)	**(253)**
Dividends on Common Shares			(6,546)	**(6,546)**
Stock Compensation Plans		321		**321**
Redemption Premium on Preferred Shares			(6)	**(6)**
Balance at December 31, 2002	41,220	990	32,140	**74,350**
Net Income for 2003			7,958	**7,958**
Dividends on Preferred Shares			(236)	**(236)**
Dividends on Common Shares			(6,813)	**(6,813)**
Stock Compensation Plans		(82)		**(82)**
Common Stock Offering—717,600 Shares	16,911			**16,911**
Issuance of 28,714 Common Shares	717			**717**
Balance at December 31, 2003	58,848	908	33,049	**92,805**
Net Income for 2004			8,226	**8,226**
Dividends on Preferred Shares			(215)	**(215)**
Dividends on Common Shares			(7,623)	**(7,623)**
Stock Compensation Plans		151		**151**
Issuance of 35,310 Common Shares	947			**947**
Balance at December 31, 2004	**$59,795**	**$1,059**	**$33,437**	**$94,291**

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

Note 1: Summary of Significant Accounting Policies

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 (PUHCA). The following companies are wholly-owned subsidiaries of Unitil: Unitil Energy Systems, Inc. (UES) (formed in 2002 by the combination and merger of Unitil's former utility subsidiaries Concord Electric Company and Exeter & Hampton Electric Company), Fitchburg Gas and Electric Light Company (FG&E), Unitil Power Corp. (Unitil Power), Unitil Realty Corp. (Unitil Realty), Unitil Service Corp. (Unitil Service) and its non-regulated business unit Unitil Resources, Inc. (Unitil Resources). Usource, Inc. and Usource L.L.C. are subsidiaries of Unitil Resources.

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

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

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

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: UES and FG&E. Both UES and FG&E 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 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 and a summary of the Company's Regulatory Assets is provided below. 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 and natural gas from various suppliers. The annual costs under these contracts are included in Purchased Electricity and Purchased Gas in the Consolidated Statements of Earnings and these costs are recoverable in current and future rates under various orders issued by the FERC, MDTE and NHPUC.

	December 31,	
Regulatory Assets consist of the following (000's)	**2004**	**2003**
Power Supply Buyout Obligations	**$140,448**	$167,341
Income Taxes	**20,670**	22,507
Recoverable Deferred Restructuring Charges	**30,840**	28,311
Recoverable Generation-related Assets	**5,169**	7,291
Pension / Post-retirement Benefits Other than Pension	**2,481**	2,078
Total Regulatory Assets	**$199,608**	$227,528

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. 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 for regulatory assets under SFAS No. 71 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 December 31, 2004. There are no significant intangible assets recorded by the Company at December 31, 2004. Therefore, the Company is not currently involved in making estimates or seeking valuations of these items.

Off-Balance Sheet Arrangements—As of December 31, 2004, 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 December 31, 2004, 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 estimated. 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 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. See Note 9.

Pension income is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on Plan assets of 8.75%, 8.75% and 9.25% for 2004, 2003 and 2002, respectively. In developing the expected long-term rate of return assumption, the Company evaluated input from actuaries, bankers and investment managers. The Company's expected long-term rate of return on Plan assets is based on target asset allocation assumptions of 60% in United States equities and 40% in fixed income securities. The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 8.75% for 2004. The Company will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the appropriate assumptions as necessary.

The Company bases the actuarial determination of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a three-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a three-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized. The Company's pension expense (income) for the years 2004, 2003 and 2002 was $1,981,667, $1,106,827 and ($166,472), respectively. Had the Company used the fair value of assets instead of the market-related value, pension expense (income) for the years 2004, 2003 and 2002 would have been $2,119,667, $2,332,699 and $614,685, respectively.

The discount rate that is utilized in determining future pension obligations is based on a basket of long-term bonds that receive one of the two highest ratings given by a recognized rating agency. The discount rates used for the 2004, 2003 and 2002 fiscal years were 6.50%, 7.00% and 7.25%, respectively. For 2004, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $200,000 in the Net Periodic Pension Cost. Similarly, for 2002 and 2003, a change in the discount rate of 0.25% would have resulted in an increase or decrease of approximately $50,000 and $150,000, respectively. The effect of a change in discount rates for 2003 and 2004 would have been greater than for 2002 because of the significant market declines that affected 2003 and 2004 pension costs. The compensation increase assumptions used for 2002, 2003 and 2004 were 4.00%, 4.00% and 3.50%, respectively, based on the expected increase in payroll for personnel covered by the Plan.

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 policy is to record those estimates in accordance with the American Institute of Certified Public Accountants 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. As of December 31, 2004, the Company is not aware of any material commitments or contingencies other than those disclosed in the Significant Contractual Obligations table in the Contractual Obligations section above in Item 7 and the Commitments and Contingencies footnote to the Company's consolidated financial statements below.

Utility Plant—The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 1.64%, 2.14% and 3.48% in 2004, 2003 and 2002, respectively. 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. The Company does not account separately for negative salvage, or cost of retirement obligations as defined in SFAS No. 143, "Accounting for Asset Retirement Obligations". 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. At December 31, 2004 and December 31, 2003, the Company estimates that the negative salvage value of future retirements recorded on the balance sheet in Accumulated Depreciation is $12.7 million and $12.2 million, respectively.

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. 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.

Depreciation provisions for Unitil's utility operating subsidiaries are determined on a group straight-line basis. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2004 – 4.70%, 2003 – 4.73% and 2002 – 3.79%.

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. In the past three years, the Company has 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 December 31, 2004, 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 (See Note 3).

Income Taxes—Income tax expense is calculated in each of the jurisdictions in which the Company operates for each period for which a statement of income is presented. This process involves estimating the Company's actual current tax liabilities as well as assessing temporary and permanent differences resulting from differing treatment of items, such as timing of the deduction of expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities, which are included in the consolidated balance sheets. The Company must also assess the likelihood that the deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance must be established. Significant management judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances. The Company accounts for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." The Company does not currently have any valuation allowances against its recorded deferred tax amounts. See Note 8.

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 June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. The Company initiated a reorganization of management and administrative positions in the fourth quarter of 2002 and recognized a Restructuring Charge, discussed below in Note 2, under the provisions of Emerging Issues Task Force (EITF) Issue No. 94-3, the predecessor standard to SFAS 146.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." SFAS No. 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value-based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method on reported results. The Company recognizes compensation cost at fair value at the date of grant.

In December 2004, the FASB issued revised SFAS No. 123(R), "Share-Based Payment", effective for periods beginning after June 15, 2005. SFAS No. 123(R) requires all entities to recognize the fair value of share-based payment awards classified in equity, unless they are unable to reasonably estimate the fair value of the award. The Company has already adopted the provisions of SFAS No. 123(R) and therefore there is no impact on the Consolidated Financial Statements.

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities" and in December 2003 issued a revised FIN 46. This interpretation clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaces the current accounting guidance relating to the consolidation of certain special purpose entities (SPE's). FIN 46 requires identification of the Company's participation in variable interest entities (VIE's) established on the basis of contractual, ownership or other monetary interests. A VIE is defined as an entity in which the equity investors do not have a controlling interest and the equity investment at risk is insufficient to fund future activities to permit the VIE to operate on a stand alone basis without receiving additional financial support.

For entities identified as VIE's, FIN 46 sets forth a model to evaluate potential consolidation based on an assessment of which party to the VIE bears a majority of the risk to the VIE's expected losses, or stands to gain from a majority of the expected returns of the VIE. The party with the majority variable interest is considered to be the Primary Beneficiary of the VIE. As a result, entities that are deemed to be VIE's in which the Company is identified as the Primary Beneficiary were required to be consolidated beginning in July 2003. At its Board meeting on October 8, 2003, the FASB decided to defer implementation of this requirement until the fourth quarter of 2003.

The Company reviewed its investments and affiliations and determined that it had a variable interest in the Unitil Retiree Trust (URT), a special purpose entity established January 1993. 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. URT was under the direction of an independent Board of Trustees whose voting members were comprised of former employees of the Company, elected by and from the membership of URT.

In the fourth quarter of 2003, URT was dissolved by a vote of its trustees and the Company assumed the obligations of URT as of October 1, 2003. At October 1, 2003, the Transition Obligation for benefits previously provided by URT was $29.2 million and this obligation is being recognized on a delayed basis over the average remaining service period of active participants, not to exceed 20 years. In addition, the Company made payments of $1.3 million and $1.2 million in 2003 and 2002, respectively, to the Unitil Retiree Trust. There are no other entities identified by the Company that qualify as VIE's under FIN 46. See Note 9 for additional discussion regarding FIN 46 and the Company's accounting for Postretirement Benefits other than Pensions.

In April 2003, the FASB issued Statement No. 149 (SFAS 149), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends and clarifies financial accounting and reporting requirements for derivative instruments, including derivative instruments embedded in other contracts, and for hedging activities under FASB Statement No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities." In general, SFAS 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company has undertaken a review of its wholesale electric and gas energy supply contracts and determined that they do not meet the criteria for classification as derivatives under SFAS 149 and/or SFAS 133. Therefore, the Company has determined that adoption of these statements did not have a material impact on the Company's financial position or results of operations. See Note 5.

In December 2003, the FASB issued Statement No. 132(R) (SFAS 132(R)), a revision of its original Statement No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" (SFAS 132). SFAS 132(R) revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, "Employers' Accounting for Pensions", No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". SFAS 132(R) retains the disclosure requirements contained in SFAS 132 and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. The Company adopted this statement in 2003.

In January 2004 and May 2004, the 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, how that effect has been, or will be, reflected in the net postretirement benefit costs of current or subsequent periods and the effects of any changes in estimates of participation rates on per capita claims cost as a result of the Act. However, since specific authoritative guidance on the accounting for the federal subsidy associated with the Act is pending, a Plan sponsor can elect to defer recognition of the effects of the Act in the accounting for its Plan under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" and in providing disclosures related to the Plan required by SFAS 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits", until that guidance is issued. The Company has elected to defer recognition of the effects of the Act until specific authoritative guidance on the accounting for the federal subsidy associated with the Act is issued. Please refer to Note 9 to the Consolidated Financial Statements, Pension and Postretirement Benefit Plans, for required disclosures related to the Company's deferral of the recognition of the effects of the Act.

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: Restructuring Charge—2002

In the fourth quarter of 2002, Unitil recognized a pre-tax Restructuring Charge of $1.6 million. In December 2002, the Company undertook a strategic review of its business operations and committed to a formal transition and reorganization plan (the Reorganization Plan) to streamline its management structure, in order to improve operating efficiency and to align the organization to meet ongoing business requirements. The Reorganization Plan resulted in the elimination of 19 management and administrative positions.

Note 3: Equity

The Company has both common and preferred stock outstanding. Details regarding these forms of capitalization follow below.

Common Stock

Public Offering 2003—On October 29, 2003, the Company raised approximately $16.9 million (after deducting underwriting discounts and commissions and the estimated expenses of the offering) through the sale of 717,600 shares of its common stock at a price of $25.40 per share in a registered public offering. The offering was increased from an original 520,000 shares to reflect a 20% upsizing of the transaction (104,000 shares) and the exercise of a 15% underwriters' over-allotment (93,600 shares). The Company used the proceeds from this offering to make capital contributions of $6 million to UES and $6 million to FG&E and for other general corporate purposes.

Dividend Reinvestment and Stock Purchase Plan—During 2004, the Company sold 35,310 shares of its Common Stock, at an average price of $26.82 per share, in connection with its Dividend Reinvestment and Stock Purchase Plan (DRP) and its 401(k) plans. Net proceeds of $946,883 were used to reduce short-term borrowings. The DRP provides participants in the plan a method for investing cash dividends on the Company's Common Stock and cash payments in additional shares of the Company's Common Stock. During 2003, the Company raised $716,936 of additional common equity through the issuance of 28,714 shares of its Common Stock in connection with the DRP. During 2002, the Company did not issue any additional shares of its Common Stock.

Shares Repurchased, Cancelled and Retired—During 2004, 2003 and 2002, Unitil did not repurchase, cancel or retire any of its common stock.

Stock-Based Compensation Plans—Unitil maintains a Restricted Stock plan and two stock option plans, which provided for the granting of options to key employees. Details of the plans are as follows:

Restricted Stock Plan—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. During the vesting period, dividends on restricted shares underlying the Award may be credited to the participant's account. Awards may be grossed up to offset the participant's tax obligations in connection with the Award. 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 April 29, 2004, 10,700 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $293,715. On May 12, 2003, 10,600 restricted shares were issued in conjunction with the Plan with an aggregate market value at the date of issuance of $259,170. The compensation expense associated with the issuance of shares under the Plan is being accrued on a monthly basis over the vesting period and was $163,400 in 2004, including amounts for tax gross-up. Issuances of shares under the Plan are subject to the prior approval of the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. The Company applied for and received such approval in April, 2004, prior to the initial vesting of the first set of awards granted in May, 2003.

Unitil Corporation Key Employee Stock Option Plan—The "Unitil Corporation Key Employee Stock Option Plan" was a 10-year plan which began in March 1989. The number of shares granted under this plan, as well as the terms and conditions of each grant, were determined by the Key Employee Stock Option Plan Committee of the Board of Directors, subject to plan limitations. At December 31, 2004, 29,101 shares had been approved and were available for future issuance as dividend equivalents earned under the plan. All options granted under this plan vested upon grant. The 10-year period in which options could be granted under this plan expired in March 1999. The expiration date of the remaining outstanding options is November 3, 2007. The plan provides dividend equivalents on options granted, which are recorded at fair value as compensation expense. The total compensation expenses recorded by the Company with respect to this plan were $49,000, $46,000 and $43,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

Share Option Activity of the "Unitil Corporation Key Employee Stock Option Plan" is presented in the following table:

	2004	2003	2002
Beginning Options Outstanding and Exercisable	**25,000**	25,000	25,000
Dividend Equivalents Earned—Prior Years	**9,495**	7,645	5,996
Dividend Equivalents Earned—Current Year	**1,826**	1,850	1,649
Options Exercised	**—**	—	—
Ending Options Outstanding and Exercisable	**36,321**	34,495	32,645
Weighted Average Exercise Price per Share	**$12.51**	$13.17	$13.91
Range of Option Exercise Price per Share	**$12.11-$18.28**	$12.11-$18.28	$12.11-$18.28
Weighted Average Remaining Contractual Life	**2.9 years**	3.9 years	4.9 years

Unitil Corporation 1998 Stock Option Plan—The "Unitil Corporation 1998 Stock Option Plan" became effective on December 11, 1998. The number of shares granted under this plan, as well as the terms and conditions of each grant, are determined by the Compensation Committee of the Board of Directors, subject to plan limitations. All options granted under this plan vest over a three-year period from the date of the grant, with 25% vesting on the first anniversary of the grant, 25% vesting on the second anniversary, and 50% vesting on the third anniversary. Under the terms of this plan, key employees may be granted options to purchase the Company's Common Stock at no less than 100% of the market price on the date the option is granted. All options must be exercised no later than 10 years after the date on which they were granted. There was no compensation expense associated with this plan in 2004. The total compensation expenses recorded by the Company with respect to this plan were ($178,000) and $278,000 for the years ended December 31, 2003 and 2002, respectively. 2003 reflects a reversal of prior compensation expense due to stock option forfeitures. This plan was terminated on January 16, 2003. The plan will remain in effect solely for the purposes of the continued administration of all options currently outstanding under the plan. No further grants of options will be made under this plan.

	2004		2003		2002	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Beginning Options Outstanding	**107,000**	**$27.13**	172,500	$26.99	172,500	$26.99
Options Granted	**—**	**—**	—	—	—	—
Options Forfeited	**—**	**—**	(65,500)	$26.77	—	—
Ending Options Outstanding	**107,000**	**$27.13**	107,000	$27.13	172,500	$26.99
Options Vested and Exercisable-end of year	**107,000**	**$27.13**	107,000	$27.13	100,500	$26.11

The Company has adopted SFAS No. 123, "Accounting for Stock Based Compensation," and recognizes compensation costs at fair value at the date of grant.

The following summarizes certain data for options outstanding at December 31, 2004:

Range of Exercise Prices	Options Vested, Exercisable and Outstanding	Weighted Average Exercise Price	Remaining Contractual Life
$20.00-$24.99	34,500	$23.38	4.2 years
$25.00-$29.99	37,500	$25.88	6.1 years
$30.00-$34.99	35,000	$32.17	5.1 years
	107,000		

There were no options granted during 2004, 2003 or 2002.

Restrictions on Retained Earnings—Unitil Corporation has no restriction on the payment of common dividends from retained earnings.

Its two retail distribution subsidiaries, UES and FG&E, do have restrictions. Under the terms of the First Mortgage Bond Indentures, UES had $12,514,000 available for the payment of cash dividends on its Common Stock at December 31, 2004. Under the terms of long-term debt purchase agreements, FG&E had $6,696,000 of retained earnings available for the payment of cash dividends on its Common Stock at December 31, 2004. Common dividends declared by UES and FG&E are paid exclusively to Unitil Corporation.

Preferred Stock

Unitil's two retail distribution companies, UES and FG&E, have preferred stock outstanding. At December 31, 2004, UES has a 6.00% Series Non-Redeemable, Non-Cumulative Preferred Stock series outstanding and FG&E has two series of Redeemable, Cumulative Preferred Stock outstanding, the 5.125% Series and the 8.00% Series.

FG&E is required to offer to redeem annually a given number of shares of each series of Redeemable, Cumulative Preferred Stock and to purchase such shares that shall have been tendered by holders of the respective stock. In addition, FG&E may opt to redeem the Redeemable, Cumulative Preferred Stock at a given redemption price, plus accrued dividends.

The aggregate purchases of Redeemable, Cumulative Preferred Stock during 2004, 2003 and 2002 related to the annual redemption offer were $26,900, $53,400 and $34,500, respectively. The aggregate amount of sinking fund requirements of the Redeemable, Cumulative Preferred Stock for each of the five years following 2004 is $117,000 per year.

On October 15, 2004, UES redeemed and retired the remaining three outstanding issues of its Redeemable, Cumulative Preferred Stock at par, aggregating $904,100. The three issues redeemed and retired were the 8.70% Series (aggregate par value of $215,000), the 8.75% Series (aggregate par value of $313,600) and the 8.25% Series (aggregate par value of $375,500). UES used operating cash to effect this transaction.

Also, during 2002, in conjunction with the merger of E&H into CECo to form UES (E&H and CECo were UES' predecessor companies), the 5% and 6% series of Redeemable, Cumulative Preferred Stock were fully redeemed at par plus premiums of 2% and 3%, respectively. These redemptions and related premiums resulted in an aggregate expenditure of $258,720.

Note 4: Long-Term Debt, Credit Arrangements, Leases and Guarantees

The Company funds a portion of its operations through the issuance of long-term debt and through short-term borrowing arrangements. The Company's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery and office equipment. Details regarding long-term debt, short-term debt and leases follows below.

Long-Term Debt and Interest Expense

Substantially all the property of Unitil's New Hampshire utility operating subsidiary, UES, is subject to liens of indenture under which First Mortgage bonds have been issued. All of the long-term debt of Unitil's Massachusetts utility operating subsidiary, FG&E, is issued under Unsecured Promissory Notes with negative pledge provisions. Each issue of FG&E's long-term debt ranks pari passu with its other senior unsecured long-term debt. The long-term debt's negative pledge provisions contain restrictions which, among other things, limit the incursion of additional long-term debt.

Total aggregate amount of sinking fund payments relating to bond issues and normal scheduled long-term debt repayments amounted to $3,264,421, $3,244,156 and $3,225,444 in 2004, 2003 and 2002, respectively.

The aggregate amount of bond sinking fund requirements and normal scheduled long-term debt repayments for each of the five years following 2004 is: 2005 – $286,368, 2006 – $310,136, 2007 – $335,877, 2008 – $363,755 and 2009 – $393,946.

On October 28, 2003, FG&E completed a $10 million private placement of long-term unsecured notes with a major insurance company. The notes have a term of 22 years and a coupon rate of 6.79%. The net proceeds were used to replace short-term indebtedness.

The fair value of the Company's long-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company for debt of the same remaining maturities. In management's opinion, the carrying value of the debt approximated its fair value at December 31, 2004 and 2003.

The agreements under which the long-term debt of Unitil's two principal subsidiaries, UES and FG&E, were issued contain various covenants and restrictions. These agreements do not contain any covenants or restrictions pertaining to the maintenance of financial ratios or the issuance of short-term debt. These agreements do contain covenants relating to, among other things, the issuance of additional long-term debt, cross-default provisions and business combinations, as described below.

UES utilizes a First Mortgage Bond (FMB) structure of long-term debt. In order to issue new FMB securities, the customary covenants of the existing UES Indenture Agreement must be met, including that UES have sufficient available net bondable plant to issue the securities and projected earnings available for interest charges equal to at least two times the annual interest requirement. The UES agreements further require that if

UES defaults on any UES FMB securities, it would constitute a default for all UES FMB securities. The UES default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

FG&E utilizes a debenture structure of long-term debt. Accordingly, in order for FG&E to issue new long-term debt, the covenants of the existing long-term agreements must be satisfied, including that FG&E have total funded indebtedness less than 65% of total capitalization and earnings available for interest equal to at least two times the interest charges for funded indebtedness. As with the UES agreements, FG&E agreements require that if FG&E defaults on any FG&E long-term debt agreement, it would constitute a default under all FG&E long-term debt agreements. The FG&E default provisions are not triggered by the actions or defaults of other companies in the Unitil System.

Both the UES and FG&E instruments and agreements contain covenants restricting the ability of each company to incur liens and to enter into sale and leaseback transactions, and restricting the ability of each company to consolidate with, to merge with or into, or to sell or otherwise dispose of all or substantially all of its assets.

Interest Expense, net—Interest expense is presented in the financial statements net of interest income. Interest expense is mainly comprised of interest on long-term debt and 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. A summary of interest expense and interest income is provided in the following table:

Interest Expense, net (000's)	2004	2003	2002
Interest Expense			
Long-term Debt	**$ 8,492**	$ 8,170	$ 8,336
Short-term Debt	**629**	1,071	1,037
Subtotal Interest Expense	**9,121**	9,241	9,373
Interest Income			
Regulatory Assets	**(2,310)**	(1,657)	(2,090)
AFUDC and Other	**(16)**	(46)	(52)
Other	**(21)**	(7)	(174)
Subtotal Interest Income	**(2,347)**	(1,710)	(2,316)
Total Interest Expense, net	**$ 6,774**	$ 7,531	$ 7,057

Credit Arrangements

At December 31, 2004, Unitil had unsecured committed bank lines for short-term debt in the aggregate amount of $33.0 million with three banks for which it pays commitment fees. The weighted average interest rates on all short-term borrowings were 1.9%, 1.8% and 2.2% during 2004, 2003 and 2002, respectively.

Leases

Unitil's subsidiaries conduct a portion of their operations in leased facilities and also lease some of their machinery and office equipment. FG&E had a 22-year facility lease in which the Primary Term was scheduled to end on January 31, 2003. On February 1, 2003, a 10-year Extended Term commenced extending the lease term through January 31, 2013. Furthermore, the amended lease agreement allows for three additional five-year renewal periods at the option of FG&E. This lease, as well as other leases for equipment used by Unitil's subsidiaries, is recorded as an operating lease. In prior years, this lease was classified as a capital lease. The change in classification was the result of the renegotiation of the lease terms described above.

The following is a schedule of the leased property under capital leases by major classes:

Classes of Utility Plant (000's)	Asset Balances at December 31, 2004	2003
Common Plant	**$2,769**	$3,443
Less: Accumulated Depreciation	**2,197**	2,507
Net Plant	**$ 572**	$ 936

The following is a schedule of future minimum lease payments and present value of net minimum lease payments under capital leases, as of December 31, 2004:

Year Ending December 31 (000's)	
2005	$440
2006	139
2007	42
2008	13
2009	8
2010-2014	4
Total Minimum Lease Payments	$646
Less: Amount Representing Interest	74
Present Value of Net Minimum Lease Payments	$572

Total rental expense charged to operations for the years ended December 31, 2004, 2003 and 2002 amounted to $249,000, $294,000 and $4,000 respectively.

The following is a schedule of future operating lease payment obligations as of December 31, 2004:

Year Ending December 31 (000's)	
2005	$ 270
2006	270
2007	270
2008	270
2009	270
2010-2014	832
Total Future Operating Lease Payments	$2,182

Guarantees

The Company also provides limited guarantees on certain energy contracts entered into by the retail distribution utilities. The Company's policy is to limit these guarantees to two years or less. As of December 31, 2004 there are $1.0 million of guarantees outstanding and these guarantees extend through October 14, 2006.

Note 5: Energy Supply

Electricity Supply:

Unitil's customers in both New Hampshire and Massachusetts now have the opportunity to purchase their electric supply from competitive retail suppliers, though most customers continue to purchase such supplies through the retail distribution companies. The transition to retail choice required the divestiture of Unitil's existing power supply arrangements and the procurement of replacement supplies which provided the flexibility for migration of customers to and from utility service, and the continuation of transmission arrangements for all customers, since this function has not been opened to retail choice and continues to be performed by the local utility. FG&E, UES, and Unitil Power each are members of the New England Power Pool (NEPOOL) for the purpose of facilitating these wholesale electric power supply transactions, which are necessary to serve Unitil's retail customers.

Wyman Unit No. IV—FG&E continues to have a 0.1822% non-operating ownership interest in the Wyman Unit No. IV, an oil-fired electric generating station located in Yarmouth, Maine (Wyman IV). The lead operating owner of Wyman IV is FPL Energy Wyman IV, LLC. In accordance with the Massachusetts Restructuring Act, and pursuant to the generation assets and power supply divestiture process discussed below, FG&E effectively divested its economic interest in Wyman IV when it entered into an agreement with Select Energy, Inc. to, among other things, sell its entire entitlement in the output from Wyman IV over the expected remaining operating life of the unit. Kilowatt-hour generation and operating expenses associated with Wyman IV are divided on the same basis as ownership. FG&E's proportionate ownership costs in Wyman IV are reflected in the Consolidated Statements of Earnings. Revenues from the entitlement sale of Wyman IV reflect a matching and collection of these costs. Accordingly, the cost associated with FG&E's ownership in Wyman IV does not have a material impact on earnings.

Information with respect to FG&E's ownership in Wyman Unit No. IV, at December 31, 2004, is shown below:

Joint Ownership Unit	State	Proportionate Ownership	Share of Total MW	Company's Net Book Value (000's)
Wyman Unit No. IV	ME	0.1822%	1.13	$50

Power Supply Divestiture

Prior to May 1, 2003, UES purchased all of its power supply from Unitil Power under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, UES and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to UES ceased and Unitil Power sold its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement UES continues to pay contract release payments to Unitil Power for costs associated with the portfolio sale and its other ongoing, power supply-related costs. Recovery of the Contract Release Payments by UES from its retail customers has been approved by the NHPUC on a fully reconciling basis.

Unitil Power divested its long-term power supply contracts to a subsidiary of Mirant Corporation, Mirant Americas Energy Marketing, LP (Mirant), which was approved by the NHPUC on March 14, 2003. The purchase of power to supply UES' Transition Service and Default Service requirements by UES from Mirant was linked to the Unitil Power divestiture. The NHPUC Order completed the state approval process for Unitil's restructuring plan under which UES implemented customer choice for its customers on May 1, 2003. The divested power supply contracts continue through October 2010.

FG&E divested its owned generation assets and long-term power supply contracts to Select Energy, Inc., a subsidiary of Northeast Utilities. Under the Select Energy contract, which was approved by the MDTE in January 2000, and went into effect February 1, 2000, FG&E began selling the entire output from its remaining long-term power supply contracts and the output of its two joint ownership units to Select Energy, Millstone Unit 3 and Wyman Unit No. IV. Upon the sale of FG&E's share of Millstone Unit 3 in 2001, this portion of the contract sale ceased. Effective with the termination of the Purchased Power Contract between FG&E and Linweave, Inc. on December 1, 2004, this portion of the contract sale also ceased.

Recovery of all costs associated with the sale of the FG&E power supply portfolio and with the aforementioned transmission payments from FG&E's retail customers has been approved by the MDTE.

Regulated Energy Supply

In order to provide regulated electric supply as the provider of last resort to their respective retail customers, the retail distribution companies enter into wholesale electric power supply contracts with various wholesale suppliers. In particular, FG&E has entered into power supply contracts to meet its power supply obligations associated with the provision of Standard Offer Service and Default Service. Standard Offer Service is offered only to customers who have both taken service from FG&E since the inception of retail choice in 1998 and have not switched to a competitive retail supplier. All other FG&E customers are eligible for Default Service. FG&E has power supply contracts with various wholesale suppliers for the provision of Default Service. MDTE policy dictates the pricing structure and duration of each of these contracts. Currently, all Default Service power supply contracts for large general accounts are three months in duration. Default Service power supply contracts for residential and small and medium general service customers are acquired every 6 months, with each 12 month contract providing 50% of the class requirements.

Currently, the MDTE is investigating alternatives to the current procurement policy for all accounts, other than the large general accounts. This process could potentially lead to the procurement of FG&E Default Service power supply for longer duration in order to provide more price stability for smaller customers throughout Massachusetts for whom competitive retail options are relatively scarce.

UES has entered into a power supply contract to meet its power supply obligations associated with the provision of Transition Service and Default Service. Transition Service is available to any UES customer, who has not chosen a competitive retail supplier. UES' Default Service is available to any customer, who has chosen a competitive retail energy supplier. UES has entered into a power supply contract for the provision of Transition Service and Default Service with Mirant. This power supply contract provides fixed unit prices for both Transition Service and Default Service for UES' largest general service accounts through April 2005 and for all other accounts through April 2006.

On July 14, 2003 Mirant Corporation and its subsidiaries filed for Chapter 11 Bankruptcy protection. On December 11, 2003 the bankruptcy court entered an order, which accepted a settlement agreement between Unitil and Mirant, under which Mirant agreed to assume both the power supply contract divestiture between Unitil Power and Mirant and the power supply contract for Transition Service and Default Service between UES and Mirant. Mirant is currently performing all of its contractual obligations to both Unitil Power and UES and has satisfied all of its pre-petition claims made by Unitil.

On October 26, 2004, UES filed with the NHPUC for the authority to offer Transition Service to its largest general service customers for one year, beginning May 2005 and ending April 2006. UES also proposed to contract for two 6-month contracts for a replacement supply contract for Transition Service and Default Service. On January 7, 2005 the NHPUC approved UES' filing. UES intends to file a comprehensive proposal with the NHPUC, which will address power supply procurement after April 30, 2006.

Gas Supply:

FG&E's natural gas customers now have the opportunity to purchase their natural gas supply from third-party vendors, though most customers continue to purchase such supplies at regulated rates through FG&E as the provider of last resort. The costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered through periodically-adjusted rates and are included in Purchased Gas in the Consolidated Statements of Earnings.

FG&E distributes natural gas purchased from domestic and Canadian suppliers under contracts of one year or less, as well as gas purchased from producers and marketers on the spot market. The following tables summarize actual gas purchases by source of supply and the cost of gas sold for the years 2002 through 2004.

Sources of Gas Supply
(Expressed as percent of total MMBtu of gas purchased)

	2004	2003	2002
Natural Gas:			
Domestic firm	**85.0%**	94.0%	73.9%
Canadian firm	**5.4%**	1.3%	8.4%
Domestic spot market	**5.9%**	1.3%	16.2%
Total natural gas	**96.3%**	96.6%	98.5%
Supplemental gas	**3.7%**	3.4%	1.5%
Total gas purchases	**100.0%**	100.0%	100.0%

Cost of Gas Sold

	2004	2003	2002
Cost of gas purchased and sold per MMBtu	**$8.42**	$7.14	$ 4.96
Percent Increase (Decrease) from prior year	**17.9%**	43.9%	(30.4%)

FG&E has available under firm contract 14,057 MMbtu per day of year-round and seasonal transportation and underground storage capacity to its distribution facilities. As a supplement to pipeline natural gas, FG&E owns a propane air gas plant and a liquefied natural gas (LNG) storage and vaporization facility. These plants are used principally during peak load periods to augment the supply of pipeline natural gas.

Note 6: Commitments and Contingencies

Regulatory Matters

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 Massachusett's 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 $176 million as of December 31, 2004 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 has also 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. FG&E was required to provide Standard Offer through February 2005 at rate levels which provide state-mandated rate reductions. New distribution customers and customers no longer eligible for Standard Offer were eligible to receive Default Service at prices set periodically based on market solicitations as approved by the MDTE. As of December 31, 2004, competitive suppliers were serving approximately 36 percent of FG&E's electric load, primarily for FG&E's largest customers. On March 1, 2005, customers on Standard Offer will be automatically placed on Default Service.

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 ends 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 has advised the MDTE that it will file a proposed plan for recovery of these deferred amounts beginning March 1, 2005. The value of FG&E's generation-related and deferred-cost Regulatory Assets was approximately $35.0 million at December 31, 2004, and $31.7 million at December 31, 2003, and is expected to be recovered in FG&E's rates over the next 6 to 8 years. In addition, as of December 31, 2004, FG&E had recorded on its balance sheets $65.7 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—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 December 31, 2004, FG&E has recorded a regulatory asset of $1.6 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 December 31, 2004, UES had recorded on its balance sheets $74.7 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 7 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 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 allow deferral of its pension expenses above the level recovered in base rates of $0.6 million for 2004 until UES files its next base rate case which will be filed no later than October, 2007. This matter remains pending.

Effective as of February 1, 2005, the Restructuring Surcharge in UES rates, which has been in place since December 2002, will expire, resulting in a rate decrease of approximately 1 percent. The tariff allowing for collection of this charge provides that it will terminate when all costs have been collected.

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.

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. FGE and UES have intervened in the proceeding. Both UES and FG&E are located in a non-constrained area of the power pool which should have modest LICAP prices for several years under the filed proposal. 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. 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.

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.

Former Electric Generating Station—In 2003, FG&E completed environmental remediation action to abate and remove asbestos-containing and other hazardous materials at a former electric generating station located at Sawyer Passway in Fitchburg, Massachusetts, which FG&E sold in 1983 to a general partnership, Rockware. FG&E received significant coverage from its insurance carrier for this remediation project and the resolution of this matter did not have a material adverse effect on the Company's financial position.

Note 7: Bad Debts

The Company recognizes a Provision for Doubtful Accounts each month. The amount of the monthly Provision is based upon the Company's experience in collecting electric and gas utility service accounts receivable in prior years. Account write-offs, net of recoveries, are processed monthly. At the end of each month, an analysis of the delinquent receivables is performed and the adequacy of the Allowance for Doubtful Accounts is reviewed. The analysis takes into account an assumption about the cash recovery of delinquent receivables and also uses calculations related to customers who have chosen payment plans to resolve their arrears. The analysis also takes into account the amount of receivables that will be 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. The following table shows the balances and activity in the Company's Allowance for Doubtful Accounts for 2002—2004.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

	Balance at Beginning of Period	Additions (A) Provision	Additions Recoveries	Accounts Written Off	Balance at End of Period
Year Ended December 31, 2004					
Electric	$395,432	$ 821,077	$121,974	$ 945,659	$392,824
Gas	132,964	524,905	96,411	664,678	89,602
Other	13,080	10,500	—	5,283	18,297
	$541,476	$1,356,482	$218,385	$1,615,620	$500,723
Year Ended December 31, 2003					
Electric	$271,679	$ 719,761	$ 87,922	$ 683,930	$395,432
Gas	100,300	609,037	67,398	643,771	132,964
Other	61,630	90,000	—	138,550	13,080
	$433,609	$1,418,798	$155,320	$1,466,251	$541,476
Year Ended December 31, 2002					
Electric	$456,850	$ 323,401	$138,010	$ 646,582	$271,679
Gas	142,843	294,051	64,570	401,164	100,300
Other	—	61,630	—	—	61,630
	$599,693	$ 679,082	$202,580	$1,047,746	$433,609

(A) The amounts charged to the Provision for Doubtful Accounts include amounts related to the energy commodity portion of accounts receivable which are recovered through rate reconciling mechanisms.

Note 8: Income Taxes

Federal Income Taxes were provided for the following items for the years ended December 31, 2004, 2003 and 2002, respectively:

	2004	2003	2002
Current Federal Tax Provision (000's):			
Operating Income	**$ 438**	$(2,898)	$1,960
Amortization of Investment Tax Credits	**—**	—	(51)
Total Current Federal Tax Provision	**438**	(2,898)	1,909
Deferred Federal Tax Provision (000's)			
Accelerated Tax Depreciation	**2,805**	3,329	68
Abandoned Properties	**(769)**	(778)	(705)
Accrued Revenue	**1,779**	2,034	1,118
Allowance for Funds Used During Construction	**(16)**	(23)	(32)
Post Retirement Benefits Other Than Pensions	**(262)**	(217)	(38)
Deferred Pensions	**259**	55	86
Regulatory Assets and Liabilities	**(194)**	146	70
Insurance Proceeds	**—**	1,172	—
Contributions in Aid of Construction	**(120)**	(201)	(231)
Net Operating Loss Carryforward	**92**	(331)	—
Alternative Minimum Tax	**(355)**	(125)	—
Other, net	**(151)**	507	(47)
Total Deferred Federal Tax Provision	**3,068**	5,568	289
Total Federal Tax Provision	**$3,506**	$ 2,670	$2,198

The components of the Federal and State income tax provisions reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2004, 2003 and 2002 are shown in the table below. In addition to the provisions for state income taxes, the Company recorded provisions of $179,000, $140,000 and $108,000 in 2004, 2003 and 2002, respectively for state Business Enterprise taxes which are included in Local Property and Other Taxes on the consolidated statements of earnings.

Federal and State Tax Provisions (000's)	2004	2003	2002
Federal			
Current	**$ 438**	$(2,898)	$1,960
Deferred	**3,068**	5,568	289
Amortization of Investment Tax Credits	**—**	—	(51)
Total Federal Tax Provision	**3,506**	2,670	2,198
State			
Current	**602**	74	(275)
Deferred	**98**	807	567
Total State Tax Provision	**700**	881	292
Total Provision for Federal and State Income Taxes	**$4,206**	$ 3,551	$2,490

The differences between the Company's provisions for Income Taxes and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown below:

	2004	2003	2002
Statutory Federal Income Tax Rate	**34%**	34%	34%
Income Tax Effects of:			
State Income Taxes, Net	**5**	5	2
Investment Tax Credit Amortization	**—**	—	(1)
Abandoned Property	**(6)**	(7)	(8)
Other, Net	**1**	(1)	2
Effective Income Tax Rate	**34%**	31%	29%

Temporary differences which gave rise to deferred tax assets and liabilities are shown below:

Deferred Income Taxes (000's)	2004	2003
Accelerated Depreciation	**$25,681**	$26,118
Deferred Restructuring Charges	**11,697**	10,070
Regulatory Assets and Liabilities	**9,164**	12,750
Employee Benefit Plan	**3,395**	3,546
Contributions in Aid of Construction	**(2,108)**	(3,901)
Retirement Loss	**3,407**	3,613
Abandoned Property	**1,535**	1,783
Percentage Repair Allowance	**1,812**	2,407
Net Operating Loss Carryforward	**(239)**	(331)
Alternative Minimum Tax Credit	**(480)**	(125)
Other	**2,292**	970
Total Deferred Income Tax Liabilities	**$56,156**	$56,900

At December 31, 2004, the Company has recorded certain deferred tax assets representing the tax effect of a federal net operating loss (NOL) carry forward of $239,000 and a federal alternative minimum tax (AMT) credit carryforward of $480,000. The NOL carry forward, if unused, expires in 2023 and the AMT credit can be carried forward indefinitely. At December 31, 2004, there is no valuation allowance recorded as an offset to these deferred tax assets. Based on the Company's history of taxable earnings and our expectations that our operations will be sufficiently profitable to utilize the NOL and AMT credit carry forwards, management has determined that operating income and the reversal of future taxable temporary differences are expected to be sufficient to realize the deferred tax assets recorded at December 31, 2004.

Note 9: 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."

The following table represents information on the Plan's Projected Benefit Obligation (PBO), fair value of plan assets and the Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2004	2003
PBO at Beginning of Year	**$47,300**	$42,745
Service Cost	**1,302**	1,151
Interest Cost	**3,028**	2,940
Plan Amendments	**—**	—
Benefits Paid	**(2,280)**	(2,270)
Actuarial (Gain) or Loss	**407**	2,734
PBO at End of Year	**$49,757**	$47,300

Change in Plan Assets (000's):	2004	2003
Fair Value of Plan Assets at Beginning of Year	**$39,337**	$34,244
Actual Return on Plan Assets	**3,247**	6,163
Employer Contributions	**2,000**	1,200
Benefits Paid	**(2,280)**	(2,270)
Fair Value of Plan Assets at End of Year	**$42,304**	$39,337

PBO and Funded Status (000's):	2004	2003
Fair Value of Plan Assets	**$42,304**	$39,337
PBO	**49,757**	47,300
Funded Status	**(7,453)**	(7,963)
Unrecognized Net (Gain) Loss	**17,727**	18,118
Unrecognized Transition (Asset) Obligation	**—**	—
Unrecognized Prior Service Cost	**716**	817
Net Amount Recognized as Prepaid Pension Asset	**$10,990**	$10,972

The following table represents information on the Plan's Accumulated Benefit Obligation (ABO), its funded status, the Company's Additional Minimum Liability (AML) and associated Regulatory Assets. The ABO is the Plan's obligation for employee service provided through December 31, 2004. An unfunded ABO represents an amount to be recognized as an additional minimum liability.

ABO and Funded Status (000's):	2004	2003
ABO	**$ 42,710**	$ 40,609
Fair Value of Plan Assets	**(42,304)**	(39,337)
Unfunded ABO/AML (Recognized as Regulatory Asset)	**$ 406**	$ 1,272

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 ABO plus one dollar. These approvals allow UES and FG&E to treat their 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 a similar proposal for a reconciling rate mechanism for the pension and postretirement costs of UES, with the NHPUC. On December 11, 2004, UES filed with the NHPUC a Petition for an Accounting Order to allow deferral of its pension expenses above the level currently recovered in base rates, until its next base rate case. In that petition the Company stated its intention to explore with the NHPUC and other interested parties, a reconciling rate mechanism for pension and PBOP 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 recent years, UES has made contributions to its pension funds which are significantly above the amounts currently collected from customers in base rates. Pension and PBOP costs have traditionally been recovered in base rates in New Hampshire and the Company has proposed consideration of a reconciling mechanism for these costs in the context of its next base rate case. The Company's petition for an Accounting order is currently pending before the NHPUC and the Company expects a decision on that petition in the first quarter of 2005.

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

Components of NPPC (000's)	2004	2003	2002
Service Cost	**$ 1,302**	$ 1,151	$ 1,116
Interest Cost	**3,028**	2,940	2,797
Expected Return on Plan Assets	**(3,393)**	(3,573)	(4,181)
Amortization of Prior Service Cost	**101**	102	102
Amortization of Transition (Asset) Obligation	**—**	—	—
Amortization of Net (Gain) Loss	**944**	487	—
Subtotal NPPC	**1,982**	1,107	(166)
Amounts Capitalized and Deferred	**(1,926)**	(758)	98
NPPC Recognized	**$ 56**	$ 349	$ (68)

Included in the amounts above for Amounts Capitalized and Deferred are $1,161,000 and $350,000 recorded as Regulatory Assets on the Company's Balance Sheet for 2004 and 2003, respectively. The remaining amounts represent amounts capitalized to construction overheads.

Key Assumptions (Weighted Average)	2004	2003	2002
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.50%**	6.50%	7.00%
Rate of Compensation Increase	**3.50%**	3.50%	4.00%
Used to Determine NPPC for years ended December 31:			
Discount Rate	**6.50%**	7.00%	7.25%
Expected Long-Term Rate of Return on Plan Assets	**8.75%**	8.75%	9.25%
Rate of Compensation Increase	**3.50%**	4.00%	4.00%

The following table represents the Plan's weighted-average investment asset allocations at December 31:

	Target Allocation 2005	Actual Allocation at December 31		
		2004	**2003**	**2002**
Equity Securities	58-62%	**61%**	61%	58%
Debt Securities	38-42%	**39%**	39%	42%
Real Estate	0-2%	**0%**	0%	0%
Other	0-2%	**0%**	0%	0%
Total		**100%**	**100%**	**100%**

The desired investment objective is a long-term rate of return on assets that is approximately 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plan has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

The following tables represent Plan contributions and benefit payments (000's):

	2004	2003	2002
Employer Contributions	**$2,000**	$1,200	$ —
Participant Contributions	**$ —**	$ —	$ —
Benefit Payments	**$2,280**	$2,270	$2,165

Estimated Future Benefit Payments

2005	2006	2007	2008	2009	2010-2014
$2,439	$2,462	$2,538	$2,691	$2,753	$16,392

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. Included in Other Current Liabilities on the Company's Consolidated Balance Sheets at December 31, 2004 is a $3.2 million accrued liability related 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. As discussed above, the Company has initiated a proposal for a reconciling rate mechanism for the pension and postretirement costs of its New Hampshire utility, UES, with the NHPUC, to achieve the same benefits for UES and its customers that have been achieved by implementing the PAF for FG&E. The Company's petition for an accounting order is currently pending before the NHPUC and the Company expects a decision on that petition in the first quarter of 2005.

The following table represents information on the PBOP Plan's fair value of plan assets and the PBOP Plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2004	2003
PBO at Beginning of Year	**$31,991**	$ 837
Service Cost	**899**	246
Interest Cost	**1,827**	558
Plan Amendments	**—**	29,165
Benefits Paid	**(1,257)**	(331)
Actuarial (Gain) or Loss	**(5,543)**	1,516
PBO at End of Year	**$27,917**	$31,991

Change in Plan Assets (000's):	2004	2003
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**3**	—
Employer Contributions	**2,355**	331
Benefits Paid	**(1,257)**	(331)
Fair Value of Plan Assets at End of Year	**$ 1,101**	$ —

Obligation and Funded Status (000's):	2004	2003
Fair Value of Plan Assets	**$ 1,101**	$ —
PBO	**27,917**	31,991
Funded Status	**(26,816)**	(31,991)
Unrecognized Net (Gain) Loss	**(3,913)**	1,633
Unrecognized Transition (Asset) Obligation	**171**	193
Unrecognized Prior Service Cost	**27,342**	28,799
Net Amount Recognized	**$ (3,216)**	$ (1,366)

The components of net periodic postretirement benefit cost (NPPBC) are as follows:

Components of NPPBC (000's)	2004	2003
Service Cost	**$ 899**	$ 246
Interest Cost	**1,827**	558
Expected Return on Plan Assets	**—**	—
Amortization of Prior Service Cost	**1,458**	365
Amortization of Transition (Asset) Obligation	**21**	21
Amortization of Net (Gain) Loss	**—**	2
Subtotal NPPBC	**4,205**	1,192
Amounts Capitalized and Deferred	**(2,498)**	(942)
NPPBC Recognized	**$ 1,707**	$ 250

Included in the amounts above for Amounts Capitalized and Deferred are $718,000 and $457,000 recorded as Regulatory Assets on the Company's Balance Sheet for 2004 and 2003, respectively. The remaining amounts represent amounts capitalized to construction overheads.

In addition to the amounts shown above, the Company also recorded expense for payments to URT of $1.3 million in 2003.

The following table includes assumptions used in determining the various PBOP values.

Weighted-Average Assumptions	2004	2003
Used to Determine Benefit Obligations at December 31:		
Discount Rate	**6.50%**	6.50%
Rate of Compensation Increase	**N/A**	N/A
Health Care Cost Trend Rate Assumed for Next Year	**8.00%**	9.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2013**	2013
Used to Determine NPPBC for years ended December 31:		
Discount Rate	**6.50%**	7.00%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A
Rate of Compensation Increase	**N/A**	N/A
Health Care Cost Trend Rate Assumed for Next Year	**9.00%**	10.00%
Ultimate Health Care Cost Trend Rate	**4.00%**	4.00%
Year That the Health Care Cost Trend Rate Reaches the Ultimate Trend Rate	**2013**	2013

Assumed health care cost trend rates have a significant effect on the amounts reported. A one-percentage-point change in the assumed health care cost trend rates would have the following effects:

1-Percentage Point Increase (000's)	2004	2003
Effect on Total of Service and Interest Cost	**$ 564**	$ 150
Effect on Postretirement Benefit Obligation	**$ 4,079**	$ 4,968
1-Percentage Point Decrease (000's)		
Effect on Total of Service and Interest Cost	**$ (438)**	$ (118)
Effect on Postretirement Benefit Obligation	**$(3,290)**	$(4,007)

The following tables represent PBOP contributions and benefit payments made in 2003 – 2004 and estimated future benefit payments. The employer contributions and benefit payments listed below reflect the Company's assumptions of the URT obligations, effective October 1, 2003:

(000's)	Expected 2005	2004	2003
Employer Contributions	**$2,500**	**$2,355**	$331
Participant Contributions	**$ —**	**$ —**	$ —

(000's)	2004	2003
Benefit Payments	**$1,257**	$331

Estimated Future Benefit Payments

2005	2006	2007	2008	2009	2010-2014
$1,160	$1,195	$1,279	$1,367	$1,430	$8,939

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 cost associated with the SERP amounted to approximately $194,000, $140,000 and $137,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

The following table represents information on the SERP's Projected Benefit Obligation (PBO), fair value of plan assets and the plan's funded status. The PBO includes expectations of future employee service and compensation increases.

Change in PBO (000's)	2004	2003
PBO Obligation at Beginning of Year	**$ 1,193**	$ 1,029
Service Cost	**89**	59
Interest Cost	**75**	69
Plan Amendments	**—**	40
Benefits Paid	**(72)**	(64)
Actuarial (Gain) or Loss	**(67)**	60
PBO at End of Year	**$ 1,218**	$ 1,193

Change in Plan Assets (000's):	2004	2003
Fair Value of Plan Assets at Beginning of Year	**$ —**	$ —
Actual Return on Plan Assets	**—**	—
Employer Contributions	**72**	64
Benefits Paid	**(72)**	(64)
Fair Value of Plan Assets at End of Year	**$ —**	$ —

Obligation and Funded Status (000's):	2004	2003
Fair Value of Plan Assets	**$ —**	$ —
PBO	**1,218**	1,193
Funded Status	**(1,218)**	(1,193)
Unrecognized Net (Gain) Loss	**141**	213
Unrecognized Transition (Asset) Obligation	**34**	51
Unrecognized Prior Service Cost	**18**	17
Net Amount Recognized	**$(1,025)**	$ (912)

The components of net periodic SERP cost are as follows:

Components of Net Periodic SERP Cost (000's)	2004	2003	2002
Service Cost	**$ 89**	$ 59	$ 64
Interest Cost	**75**	69	59
Expected Return on Plan Assets	**—**	—	—
Amortization of Prior Service Cost	**3**	(5)	(3)
Amortization of Transition Obligation	**17**	17	17
Amortization of Net Loss	**10**	—	—
Net Periodic SERP Cost	**$194**	$140	$137

The following table includes information regarding Unitil's SERP costs as well as key actuarial assumptions:

Additional Information (000's):	**2004**	**2003**	**2002**
Accumulated Benefit Obligation	**$ 673**	$ 675	$ 752
Weighted-Average Assumptions			
Used to Determine Benefit Obligations at December 31:			
Discount Rate	**6.50%**	6.50%	7.00%
Rate of Compensation Increase	**3.50%**	3.50%	4.00%
Used to Determine Net Periodic SERP Cost for years ended December 31:			
Discount Rate	**6.50%**	7.00%	7.25%
Expected Long-Term Rate of Return on Plan Assets	**N/A**	N/A	N/A
Rate of Compensation Increase	**3.50%**	4.00%	4.00%

The following tables represent SERP contributions and benefit payments made in 2002 – 2004 and estimated future benefit payments (000's):

	2004	**2003**	**2002**
Employer Contributions	**$ 72**	$ 64	$ 38
Participant Contributions	**$ —**	$ —	$ —

	2004	**2003**	**2002**
Benefit Payments	**$ 72**	$ 64	$ 38

Estimated Future Benefit Payments

2005	**2006**	**2007**	**2008**	**2009**	**2010-2014**
$70	$68	$66	$63	$61	$266

Employee 401(k) Tax Deferred Savings Plan—The Company sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k)) under Section 401(k) of the Internal Revenue Code, covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. The Company matches contributions, with a maximum matching contribution of 3% of current compensation. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company Common Stock fund. Participants are 100% vested in contributions made on their behalf, once they have completed three years of service. The Company's share of contributions to the plan was $499,000, $487,000 and $483,000 for the years ended December 31, 2004, 2003, and 2002, respectively.

Note 10: Earnings Per Share

The following table reconciles basic and diluted earnings per share, assuming all dilutive outstanding stock options were converted to common shares per SFAS No. 128, "Earnings per Share."

(000's except share and per share data)	**2004**	**2003**	**2002**
Earnings Available to Common Shareholders	**$ 8,011**	$ 7,722	$ 5,835
Weighted Average Common Shares Outstanding—Basic	**5,509,321**	4,877,933	4,743,696
Plus: Diluted Effect of Incremental Shares—from Assumed Conversion	**15,514**	18,396	18,470
Weighted Average Common Shares Outstanding—Diluted	**5,524,835**	4,896,329	4,762,166
Earnings per Share—Diluted	**$ 1.45**	$ 1.58	$ 1.23

Weighted average options to purchase 35,000, 72,500 and 54,000 shares of Common Stock were outstanding during 2004, 2003 and 2002, respectively, but were not included in the computation of Weighted Average Common Shares Outstanding for purposes of computing diluted earnings per share, because the effect would have been antidilutive.

Note 11: Segment Information

Unitil reported four segments: utility electric operations, utility gas operations, other, and non-regulated. Unitil is engaged principally in the retail sale and distribution of electricity in New Hampshire and both electricity and natural gas service in Massachusetts through its retail distribution subsidiaries UES and FG&E. Unitil Resources is the Company's wholly-owned non-utility unregulated subsidiary that provides consulting and management related services to customers outside of the Unitil system of affiliates. Usource, Inc. and Usource L.L.C. (collectively, Usource) are wholly-owned subsidiaries of Unitil Resources. Usource provides brokering and advisory services to large commercial and industrial customers in the northeastern United States. Unitil Realty and Unitil Service provide centralized facilities, operations and administrative services to support the affiliated Unitil companies.

Unitil Realty, Unitil Service and the holding company are included in the "Other" column of the table below. Unitil Service provides centralized management and administrative services, including information systems management and financial record keeping. Unitil Realty owns certain real estate, principally the Company's corporate headquarters. Unitil Resources and Usource are included in the Non-Regulated column below. The earnings of the holding company are principally derived from income earned on short-term investments and real property owned for Unitil and its subsidiaries' use.

The segments follow the same accounting policies as described in the Summary of Significant Accounting Policies. Intersegment sales take place at cost and the effects of all intersegment and/or intercompany transactions are eliminated in the consolidated financial statements. Segment profit or loss is based on profit or loss from operations after income taxes. Expenses used to determine operating income before taxes are charged directly to each segment or are allocated based on factors under PUHCA rules and contained in cost-of-service studies, which were included in rate applications approved by the NHPUC and MDTE. Assets allocated to each segment are based upon specific identification of such assets provided by Company records.

The following table provides significant segment financial data for the years ended December 31, 2004, 2003 and 2002:

Year Ended December 31, 2004 (000's)	Electric	Gas	Other	Non-Regulated	Total
Revenues	**$183,889**	**$28,685**	**$ —**	**$1,563**	**$214,137**
Segment Profit (Loss)	**6,649**	**1,202**	**300**	**(140)**	**8,011**
Identifiable Segment Assets	**340,800**	**94,239**	**21,069**	**902**	**457,010**
Capital Expenditures	**17,566**	**5,111**	**245**	**—**	**22,922**
Year Ended December 31, 2003 (000's)					
Revenues	$190,864	$28,612	$ 30	$1,148	$220,654
Segment Profit (Loss)	6,500	1,600	254	(632)	7,722
Identifiable Segment Assets	371,324	84,441	26,335	1,777	483,877
Capital Expenditures	17,427	4,083	410	19	21,939
Year Ended December 31, 2002 (000's)					
Revenues	$167,317	$20,283	$ 30	$ 756	$188,386
Segment Profit (Loss)	5,682	361	456	(664)	5,835
Identifiable Segment Assets	369,390	85,703	24,651	1,958	481,702
Capital Expenditures	16,676	3,859	290	—	20,825

Note 12: Quarterly Financial Information (unaudited; 000's except per share data)

Quarterly earnings per share may not agree with the annual amounts due to rounding. Basic and Diluted Earnings per Share are the same for the periods presented.

	Three Months Ended							
	March 31,		June 30,		September 30,		December 31,	
	2004	2003	2004	2003	2004	2003	2004	2003
Total Operating Revenues	**$59,493**	$64,807	**$48,606**	$49,624	**$50,049**	$52,892	**$55,989**	$53,331
Operating Income	**$ 4,626**	$ 4,672	**$ 3,303**	$ 3,372	**$ 2,955**	$ 3,352	**$ 4,309**	$ 4,054
Net Income Applicable to Common	**$ 2,747**	$ 2,479	**$ 1,546**	$ 1,418	**$ 1,207**	$ 1,438	**$ 2,512**	$ 2,388
	Per Share Data:							
Earnings Per Common Share	**$ 0.50**	$ 0.52	**$ 0.28**	$ 0.30	**$ 0.22**	$ 0.30	**$ 0.45**	$ 0.46
Dividends Paid Per Common Share	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345	**$ 0.345**	$ 0.345

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

None

Item 9A. Controls and Procedures

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). In addition, management is required to report their assessment, including their evaluation criteria, on the design and operating effectiveness of the Company's internal control over financial reporting in Form 10-K.

The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer (CEO), Chief Financial Officer (CFO) and Controller. The Company's internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles. The Company's internal control over financial reporting includes policies and procedures which provide reasonable assurances that transactions are properly initiated, authorized, recorded, reported and disclosed, and provide reasonable assurances regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

During 2004, management conducted an assessment of the Company's internal control over financial reporting reflected in the financial statements, based upon criteria established in the "Integrated Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on management's assessment, which included a comprehensive review of the design and operating effectiveness of the Company's internal control over financial reporting, management believes the Company's internal control over financial reporting is designed and operating effectively as of December 31, 2004.

Grant Thornton LLP, an independent registered public accounting firm, has audited management's assessment of the effectiveness of the internal control over financial reporting as stated in their report which is included herein.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

Information required by this Item is set forth in Part I, Item 1 of this Form 10-K. Information regarding the Company's Code of Ethics is set forth in the "Corporate Governance and Policies of the Board" section of the 2004 Proxy Statement as filed with the Securities and Exchange Commission on March 2, 2005.

Item 11. Executive Compensation

Information required by this Item is set forth in the "Report of the Compensation Committee" section of the 2004 Proxy Statement as filed with the Securities and Exchange Commission on March 2, 2005.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information required by this Item is set forth in the "Information About Directors" section of the 2004 Proxy Statement as filed with the Securities and Exchange Commission on March 2, 2005 as well as the Equity Compensation Plan Benefit Information table in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions

None

Item 14. Principal Accountant Fees and Services

Information required by this Item is set forth in the "Principal Accountant Fees and Services" section of the 2004 Proxy Statement as filed with the Securities and Exchange Commission on March 2, 2005.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) and (2) – **LIST OF FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES**

The following financial statements are included herein under Part II, Item 8, Financial Statements and Supplementary Data:

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets—December 31, 2004 and 2003
- Consolidated Statements of Earnings for the years ended December 31, 2004, 2003, and 2002
- Consolidated Statements of Capitalization—December 31, 2004 and 2003
- Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003, and 2002
- Consolidated Statements of Changes in Common Stock Equity for the years ended December 31, 2004, 2003, and 2002
- Notes to Consolidated Financial Statements

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions, are not applicable, or information required is included in the financial statements or notes thereto and, therefore, have been omitted.

(3) – **LIST OF EXHIBITS**

Exhibit Number	Description of Exhibit	Reference*
3.1	Articles of Incorporation of the Company.	Exhibit 3.1 to Form S-14 Registration Statement 2-93769
3.2	Articles of Amendment to the Articles of Incorporation Filed on March 4, 1992 and April 30, 1992.	Exhibit 3.2 to Form 10-K for 1991
3.3	By-laws of the Company.	Exhibit 4 to Form S-8 Registration Statement 333-73327
3.4	Articles of Exchange of Concord Electric Company (CECo), Exeter & Hampton Electric Company (E&H) and the Company.	Exhibit 3.3 to 10-K for 1984
3.5	Articles of Exchange of CECo, E&H, and the Company—Stipulation of the Parties Relative to Recordation and Effective Date.	Exhibit 3.4 to Form 10-K for 1984
3.6	The Agreement and Plan of Merger dated March 1, 1989 among the Company, Fitchburg Gas and Electric Light Company (FG&E) and UMC Electric Co., Inc. (UMC).	Exhibit 25(b) to Form 8-K dated March 1, 1989
3.7	Amendment No. 1 to The Agreement and Plan of Merger dated March 1, 1989 among the Company, FG&E and UMC.	Exhibit 28(b) to Form 8-K dated December 14, 1989

Exhibit Number	Description of Exhibit	Reference*
4.1	Twelfth Supplemental Indenture of Unitil Energy Systems, Inc., successor to Concord Electric Company, dated as of December 2, 2002, amending and restating the Concord Electric Company Indenture of Mortgage and Deed of Trust dated as of July 15, 1958.	Exhibit 4.1 to Form 10-K for 2002
4.2	FG&E Purchase Agreement dated March 20, 1992 for the 8.55% Senior Notes due March 31, 2004.	Exhibit 4.18 to Form 10-K for 1993
4.3	FG&E Note Agreement dated November 30, 1993 for the 6.75% Notes due November 23, 2023.	Exhibit 4.18 to Form 10-K for 1993
4.4	FG&E Note Agreement dated January 26, 1999 for the 7.37% Notes due January 15, 2028.	Exhibit 4.25 to Form 10-K for 1999
4.5	FG&E Note Agreement dated June 1, 2001 for the 7.98% Notes due June 1, 2031.	Exhibit 4.6 to Form 10-Q for June 30, 2001
4.6	Unitil Realty Corp. Note Purchase Agreement dated July 1, 1997 for the 8.00% Senior Secured Notes due August 1, 2017.	Exhibit 4.22 to Form 10-K for 1997
4.7	FG&E Note Agreement dated October 15, 2003 for the 6.79% Notes due October 15, 2025.	Exhibit 4.7 to Form 10-K for 2003
10.1	Unitil System Agreement dated June 19, 1986 providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.9 to Form 10-K for 1986
10.2	Supplement No. 1 to Unitil System Agreement providing that Unitil Power will supply wholesale requirements electric service to CECo and E&H.	Exhibit 10.8 to Form 10-K for 1987
10.3	Transmission Agreement between Unitil Power Corp. and Public Service Company of New Hampshire, effective November 11, 1992.	Exhibit 10.6 to Form 10-K for 1993
10.4	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.1 to Form 10-Q for September 30, 2003
10.5	Form of Severance Agreement between the Company and the persons listed at the end of such Agreement.	Exhibit 10.2 to Form 10-Q for September 30, 2003
10.6	Key Employee Stock Option Plan effective January 17, 1989.	Exhibit 10.56 to Form 8 dated April 12, 1989
10.7	Unitil Corporation Key Employee Stock Option Plan Award Agreement.	Exhibit 10.63 to Form 10-K for 1989
10.8	Unitil Corporation Management Performance Compensation Plan.	Exhibit 10.94 to Form 10-K/A for 1993
10.9	Unitil Corporation Supplemental Executive Retirement Plan effective as of January 1, 1987.	Exhibit 10.95 to Form 10-K/A for 1993
10.10	Unitil Corporation 1998 Stock Option Plan.	Exhibit 10.12 to Form 10-K for 1998
10.11	Unitil Corporation Management Incentive Plan.	Exhibit 10.13 to Form 10-K for 1998
10.12	Entitlement Sale and Administrative Service Agreement with Select Energy.	Exhibit 10.14 to Form 10-K for 1999

Exhibit Number	Description of Exhibit	Reference*
10.13	Purchase and Sale Agreement For New Haven Harbor.	Exhibit 10.15 to Form 10-K for 1999
10.14	Labor Agreement effective June 1, 2000 between CECo and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.13 to Form 10-K for 2000
10.15	Labor Agreement effective June 1, 2000 between E&H and The International Brotherhood of Electrical Workers, Local Union No. 1837.	Exhibit 10.14 to Form 10-K for 2000
10.16	Labor Agreement effective June 1, 2000 between FG&E and The Utility Workers of America, AFL-CIO., Local Union No. B340, The Brotherhood of Utility Workers Council.	Exhibit 10.15 to Form 10-K for 2000
10.17	Unitil Corporation 2003 Restricted Stock Plan.	Exhibit 10.16 to Form 10-K for 2002
10.18	Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement By and Among Unitil Power Corp., Unitil Energy Systems, Inc. and Mirant Americas Energy Marketing, LP.	Exhibit 10.17 to Form 10-K for 2002
10.19	Unitil Corporation Tax Deferred Savings and Investment Plan – Trust Agreement	Exhibit 10.1 to Form 10-Q for September 30, 2004
11.1	Statement Re: Computation in Support of Earnings per Share For the Company.	Filed herewith
12.1	Statement Re: Computation in Support of Ratio of Earnings to Fixed Charges for the Company.	Filed herewith
21.1	Statement Re: Subsidiaries of Registrant.	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm.	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

* The exhibits referred to in this column by specific designations and dates have heretofore been filed with the Securities and Exchange Commission under such designations and are hereby incorporated by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

UNITIL CORPORATION

Date March 2, 2005

By /s/ ROBERT G. SCHOENBERGER

Robert G. Schoenberger
Chairman of the Board Directors,
Chief Executive Officer and President

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

Signature	Capacity	Date
/s/ ROBERT G. SCHOENBERGER **Robert G. Schoenberger**	Principal Executive Officer; Director	March 2, 2005
/s/ MARK H. COLLIN **Mark H. Collin**	Principal Financial Officer	March 2, 2005
/s/ LAURENCE M. BROCK **Laurence M. Brock**	Principal Accounting Officer	March 2, 2005
/s/ MICHAEL J. DALTON **Michael J. Dalton**	Director	March 2, 2005
/s/ ALBERT H. ELFNER, III **Albert H. Elfner, III**	Director	March 2, 2005
/s/ ROSS B. GEORGE **Ross B. George**	Director	March 2, 2005
/s/ M. BRIAN O'SHAUGHNESSY **M. Brian O'Shaughnessy**	Director	March 2, 2005
/s/ CHARLES H. TENNEY, III **Charles H. Tenney, III**	Director	March 2, 2005
/s/ DR. SARAH P. VOLL **Dr. Sarah P. Voll**	Director	March 2, 2005
/s/ EBEN S. MOULTON **Eben S. Moulton**	Director	March 2, 2005
/s/ DAVID P. BROWNELL **David P. Brownell**	Director	March 2, 2005
/s/ EDWARD F. GODFREY **Edward F. Godfrey**	Director	March 2, 2005
/s/ MICHAEL B. GREEN **Michael B. Green**	Director	March 2, 2005
/s/ DR. ROBERT V. ANTONUCCI **Dr. Robert V. Antonucci**	Director	March 2, 2005