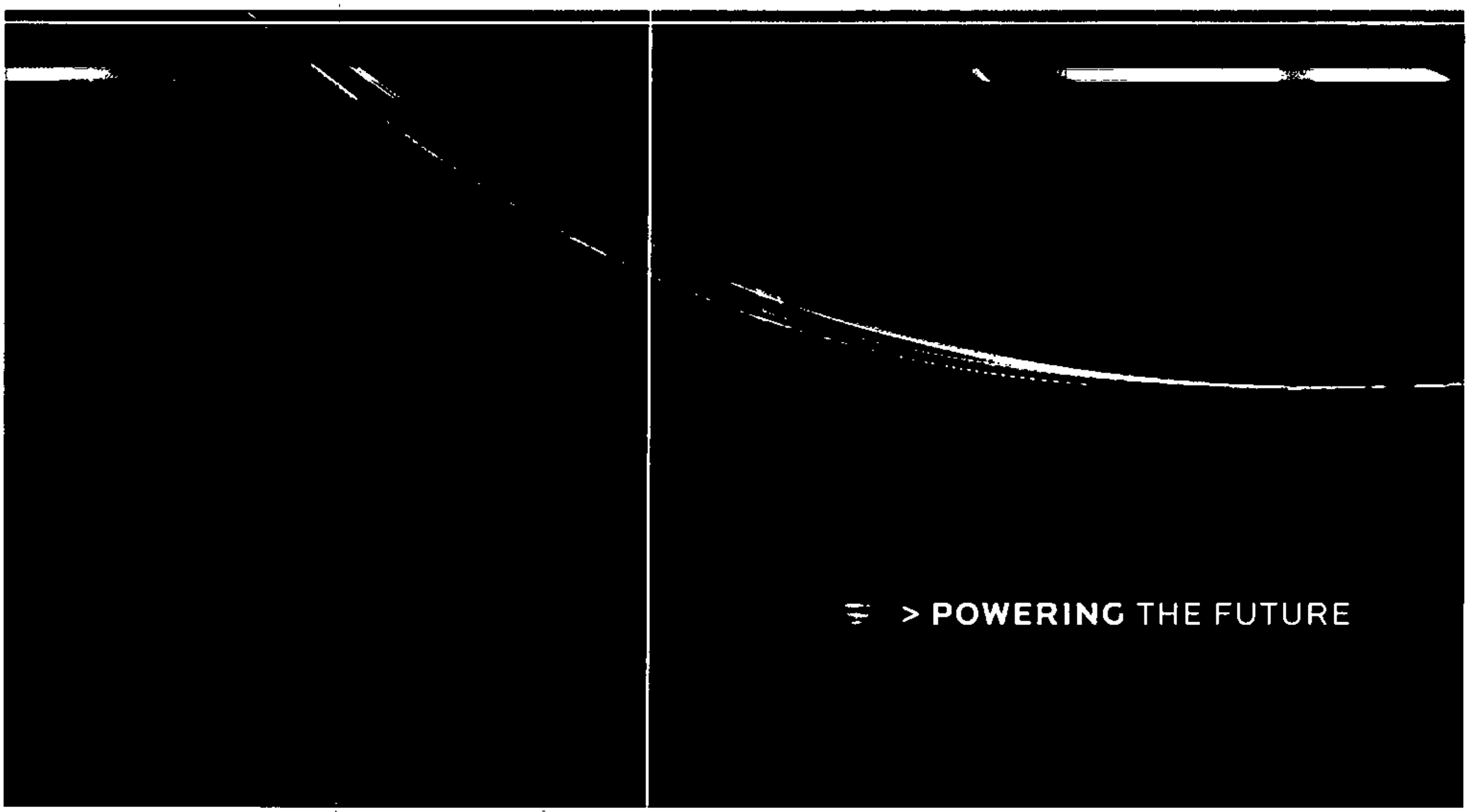
NORTHEAST UTILITIES 2007 ANNUAL REPORT



With the flip of a switch, **RELIABLE** electricity lights up a kitchen in New Hampshire and a family begins their day.

With the touch of a button, a gas furnace in Connecticut takes the chill out of the air as the local firehouse prepares a Saturday morning breakfast for the **COMMUNITY**.

And with the first rays of the sun streaming through the sky in Massachusetts, solar panels supported by Northeast Utilities (NU)-sponsored research begin to convert light to **SUSTAINABLE** energy.

Each morning represents a **FUTURE OF PROMISE**

for the more than 2 million customers we serve every day.

> THIS FUTURE **IS OURS TO DEFINE**

> TO OUR **SHAREHOLDERS, EMPLOYEES, CUSTOMERS** AND **BUSINESS PARTNERS**

Energy, Growth, Leadership: In 2007, these three simple words became our vision for the future. It is a future where Northeast Utilities continues to provide the region with reliable energy as it has done for much of the past century. It is a future where our growth is helping us deliver energy solutions for our customers and above-average returns for our shareholders. It is a future where we continue our leadership role in the region and provide our employees the opportunity to develop into tomorrow's leaders. This vision is already delivering tangible results for our shareholders and customers and is enabling us to define our future.

2007 was a good year. Total shareholder return was 14 percent, the result of an 11 percent share price increase and a 3 percent dividend yield. These results are ahead of our regulated utility peers and followed a 47 percent total return in 2006. We continue to invest in our future and that of the region by aggressively implementing a $6 billion capital program to upgrade our system. It is this financial stability and growth that enables NU to provide sound solutions to our customers' energy needs and the returns shareholders expect.

OPERATIONAL EXCELLENCE
THE FOUNDATION OF SUCCESS

Disciplined execution of our day-to-day operations and a diligent focus on our business plan were both critical to our successful performance in 2007.

We completed the first full year of operation at the Northern Wood Power project in Portsmouth, NH. This renewable wood-burning plant is dispatching power below market prices while injecting millions of dollars in additional revenue into local economies.

Yankee Gas' new liquefied natural gas storage facility is completing its first winter of operation. For customers, the 1.2 billion cubic foot facility gives Yankee Gas greater flexibility to manage its natural gas supply portfolio, allowing the company to buy natural gas in periods of low demand and lower cost and use it during the coldest days of winter when prices are usually much higher. This past winter the company saw demand for natural gas reach a near-record high — its second highest send-out day. Yankee Gas was able to use the supplies from the LNG tank rather than buying high cost gas on the spot market.

We continue to achieve recognition as a leader in new transmission construction and operation. In the first year of operation of the 345 kilovolt (kV) Bethel-to-Norwalk transmission line we reduced congestion charges by $150 million — creating tangible reliability and cost benefits for customers. There are more customer benefits to come as we are ahead of schedule for the construction of the 69-mile Middletown-to-Norwalk transmission line and on schedule for the Glenbrook Cables project and the Long Island Replacement Cable project, an 11-mile, 138 kV cable system linking Norwalk, CT, and Northport, NY.

In addition to our construction projects, we were recently recognized by the North American Electric Reliability Corporation Audit Team for our precise and excellent documentation and preparation following their extensive review of our transmission system.

At our operating companies, the distribution system is seeing significant improvements in reliability as a result of our investments. In addition, our customer service integration project is well under way and will be rolled out later this year. We opened the North Call Center in Manchester, NH, and now can take calls from anywhere in our service territories — routing them through either our North or South centers. Improved computer and customer service systems will enable us to continue our efforts to ensure a positive customer experience with every contact.

POWERING THE FUTURE
INFRASTRUCTURE INVESTMENT LEADS THE WAY

2007 earnings from NU's transmission assets represented a third of our total earnings. As we continue to invest in new transmission, we expect this segment will continue to grow and represent about 50 percent of our earnings within the next five years. We have industry-leading expertise that has enabled NU to complete projects ahead of schedule and under budget. There is an urgent need for new transmission in our region, and we are investing billions of dollars to meet this need.

Our partnership with National Grid to build the New England East-West Solution (NEEWS) will improve reliability and provide a strong transmission backbone for moving power throughout the region. This series of transmission projects will increase Connecticut's ability to import power and unlock access to renewable power generation.

Our growth is helping us provide energy solutions for our customers and the returns that our shareholders expect.

Charles W. Shivery

We recognize there is worldwide demand for transmission facilities similar to those we are building, requiring us to form strategic partnerships to complete our ambitious construction plan.

At the end of 2007, NU entered an agreement with Quanta Services to provide labor for $750 million of our transmission construction projects. We also continue to maintain a robust and diversified program to procure parts with suppliers from as far away as Japan, Finland and France, as well as manufacturers in the United States.

Continuing investments in our distribution businesses provide steady returns and strengthen the electrical system so vital to our economy and communities. In 2007 our distribution capital investments totaled $500 million across our three-state territory.

PSNH is in the early planning stage for a $250 million Clean Air project, a multi-year investment in state-of-the-art technology, to reduce mercury emissions at its Merrimack Station.

In Connecticut CL&P has submitted proposals to build 265 MW of regulated peaking generation — the first such opportunity since deregulation.

LEADING WITH ENERGY

New England faces several energy challenges in the next decade. As with many regions of the United States, there is growing demand for power and the unfortunate reality of high fuel prices. Energy efficiency and conservation must be the first measures to address rising demand. Through its award-winning, demand side management programs and its policy partnerships with groups like Environment Northeast, the Northeast Utilities companies continue to take a very active leadership role in this area. As the region's power needs continue to expand, so does society's environmental concern; renewable power standards and greenhouse gas emission reduction targets exist in every state throughout New England. We continue to actively work with policy makers and other utilities throughout the region to address the energy issues of today as we develop solutions for tomorrow.

WHERE WE LIVE AND WORK
SUPPORTING OUR COMMUNITIES

NU employees help provide reliable power in New Hampshire, Massachusetts, Connecticut and across the region. It's important to remember that this is more than just our service territory, it is also our home. That is why the Northeast Utilities Foundation and our employee volunteers maintain a strong focus on giving back to communities where we live and work.

In 2007 the NU Foundation gave more than $800,000 to local communities and made a $1 million commitment to the Connecticut Science Center. The Foundation also was a key contributor to a $2 million grant to fund an alternative energy research initiative at the University of Connecticut School of Engineering. To enhance the Foundation's ongoing role, we added $3 million to its original $25 million endowment.

In addition to the role our Foundation plays, our operating companies added more than $2.7 million in charitable contributions to local organizations across our three-state territory, and our employees raised millions of dollars more for charities.

THE PATH FORWARD

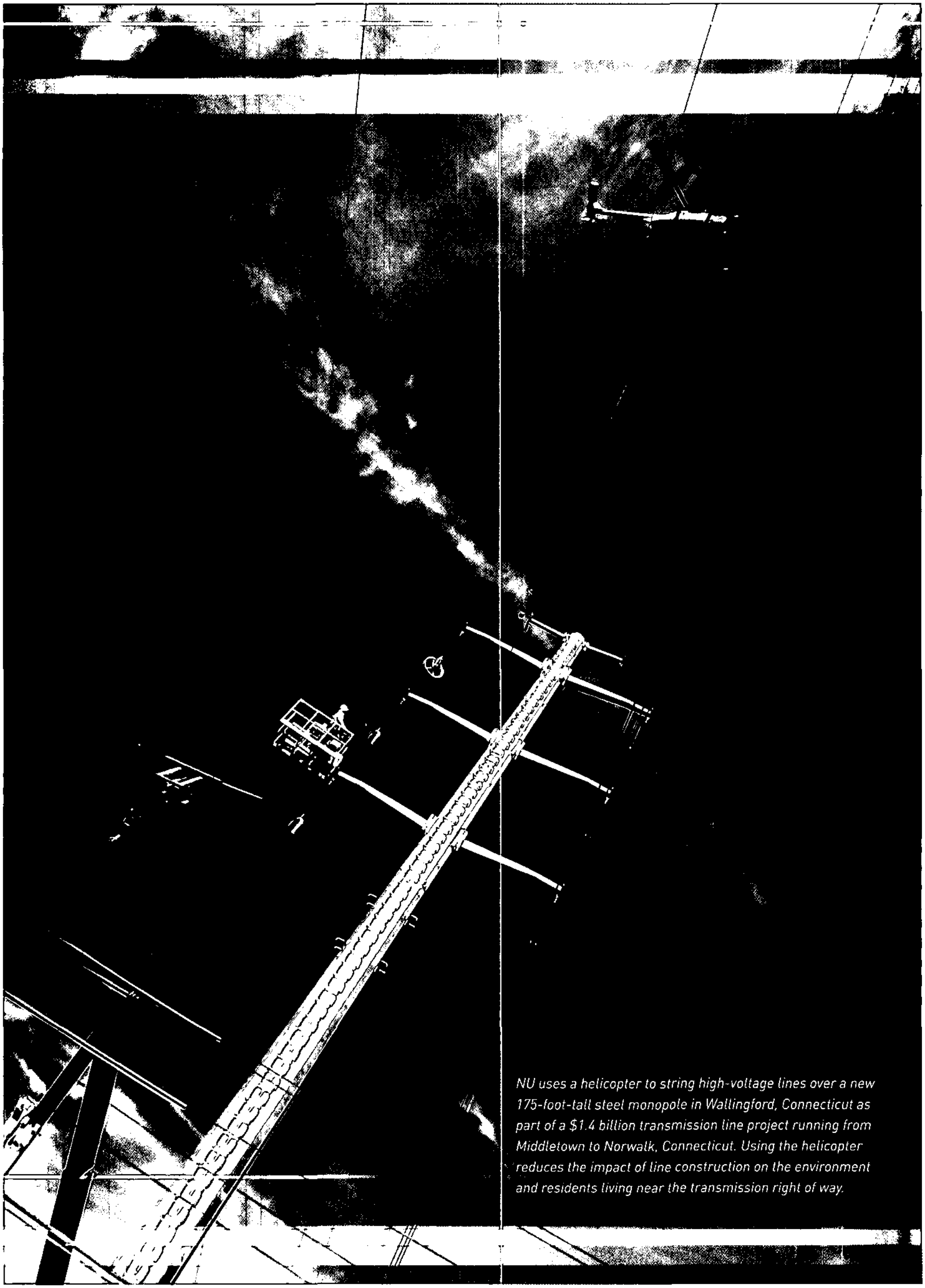
Our plan is clear and our objectives achievable. As a management team and as a company, we will continue to define the future without losing focus on the pressing needs of today. That is the essence of **Energy, Growth and Leadership.**

Sincerely,

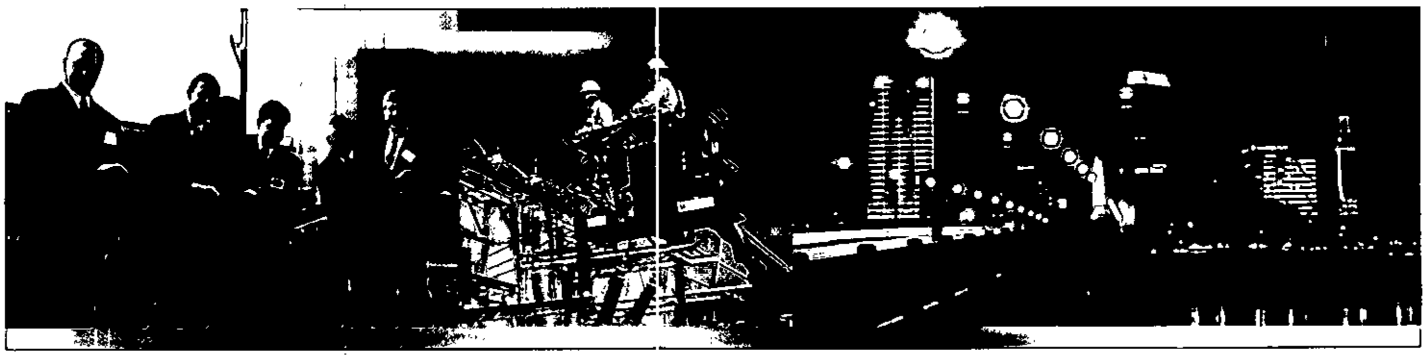
Charles W. Shivery

Charles W. Shivery
Chairman, President and Chief Executive Officer

March 5, 2008



NU uses a helicopter to string high-voltage lines over a new 175-foot-tall steel monopole in Wallingford, Connecticut as part of a $1.4 billion transmission line project running from Middletown to Norwalk, Connecticut. Using the helicopter reduces the impact of line construction on the environment and residents living near the transmission right of way.



> **RELIABILITY:** PROVIDING ENERGY WHEN YOU NEED IT

What is reliable energy? From a customer's perspective, it is trusting that the light will turn on when you flip the switch, or that the alarm clock will wake you on time each morning. But reliable energy goes well beyond these everyday conveniences — it is essential to our economy and our way of life, now and in the future. As New England's largest utility system, it is the most important measure of our success.

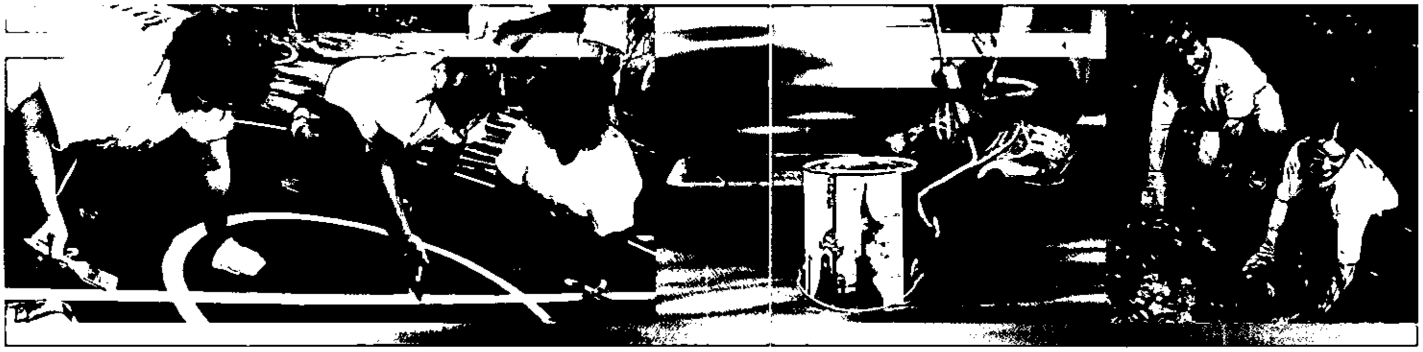
That's why — over the next few years — we will invest $6 billion in new distribution, transmission and generation projects to meet the region's growing energy needs as we prepare for the future. In 2007 we completed $500 million in upgrades to the distribution systems of our three electric companies — CL&P, PSNH and WMECO — and saw significant improvements in reliability. We also have made significant progress on the nearly $2 billion investment in the construction of new major transmission lines in southwest Connecticut. The Yankee Gas LNG facility entered its first winter of operation, and we expect customers to see reduced natural gas costs in the coming years.

Beyond reliability, a stronger grid saves our customers millions of dollars by reducing congestion costs and connecting them to competitively priced power from sources around the region. The Bethel-to-Norwalk project, completing its first year of operation, has already reduced congestion charges by $150 million — nearly 45 percent of the project's total cost. The much larger Middletown-to-Norwalk transmission project, already 70 percent complete, will serve even more customers and deliver additional savings. The Glenbrook Cables project and the Long Island Replacement Cable project will be completed in the second half of 2008 and will extend the benefits of a stable source of electricity to southwest Connecticut and the region.

We have also partnered with National Grid and the New England Independent System Operator to identify a group of projects that collectively resolve five significant transmission issues throughout the region. Known as the New England East-West Solution (NEEWS), these projects will provide stronger interconnections across Massachusetts, Rhode Island and Connecticut. Planning for these projects is currently under way.

Our diligent efforts to improve reliability have been recognized throughout the industry and our transmission build-out is ranked among the nations' Top 5 by the Edison Electric Institute.

As we look ahead, we remain focused on providing an energy infrastructure that will support continued growth in the Northeast and on maintaining a role of national leadership in the delivery of reliable energy.



> **SUPPORTING** OUR COMMUNITIES

A STRATEGIC BUSINESS INVESTMENT

The communities we serve are more than our places of work — they are where we live. The same NU employees who keep the lights on during the harshest of winters and through driving rain storms in the summers are also good neighbors, the coaches of our local little league teams and members of many volunteer organizations in the towns where they live. Giving back to communities is second nature for NU and its employees.

Last year, the Northeast Utilities Foundation gave more than $800,000 to local community initiatives, as well as a $1 million grant to the Connecticut Science Center to fund the Center's physical science gallery. The Foundation provided key funding to support an alternative energy research initiative at the University of Connecticut School of Engineering. This funding will be used to pioneer new energy technologies and create a training ground for students who will become part of tomorrow's energy workforce.

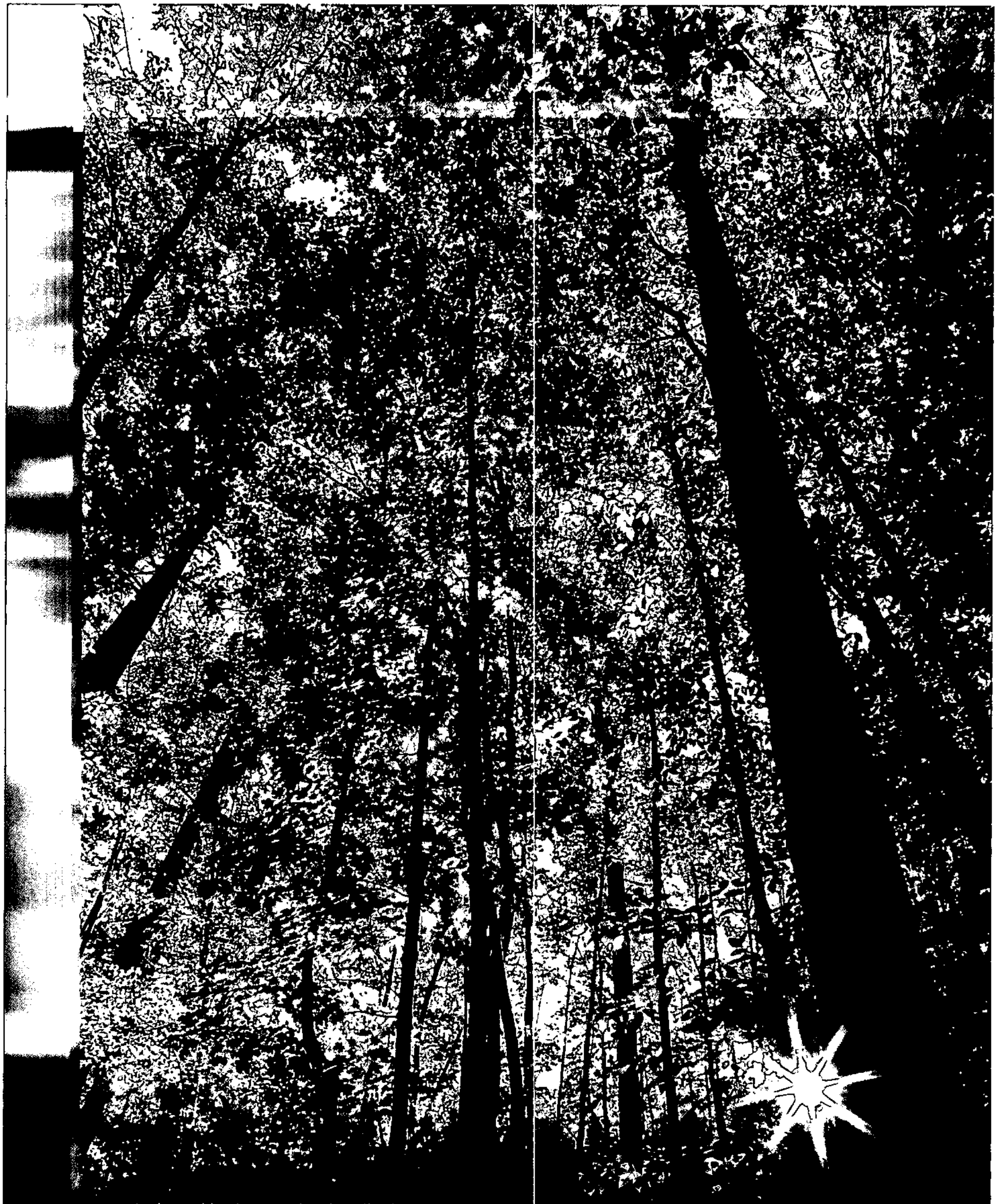
We reaffirmed our commitment to the Foundation's mission last year by adding $3 million to the original endowment of $25 million, which ensures our future investment in economic development opportunities, environmental stewardship and social responsibility initiatives throughout our region. In addition, our operating companies collectively gave more than $2.7 million to local organizations and initiatives while our employees raised millions more for local charities. Northeast Utilities is also proud to say it is the largest taxpayer in many of the hundreds of communities in our service territories. Last year NU supported its communities and states with more than $120 million in tax revenue.

Beyond financial support, our commitment to community may best be demonstrated in other tangible ways — our active support of events like the Special Olympics of Connecticut Winter Games. Several key events of the games are hosted at CL&P's Simsbury Service Center and staffed by dozens of employee volunteers. The annual United Way Day of Caring drew more than 500 NU employee volunteers last year, who spent the day performing hands-on tasks — making repairs at group homes, building handicapped access ramps, preparing meals and visiting with senior citizens. We also provide classroom presentations on electrical safety and energy efficiency at elementary schools throughout the region.

Our employees are mentors, scout leaders and volunteer firefighters. We are proud of their efforts and encourage them through programs like our Volunteer of the Year award and Dollars for Doers, which recognizes the outstanding community service efforts of individual employees and donates funding to deserving organizations on his or her behalf.

Investing — literally and figuratively — in the communities where we live and work is a gratifying part of our mission. It is sound business practice and the right thing to do.

NU's $1 million grant to the Connecticut Science Center will allow students to develop their interest in science as they become our future leaders.



As the world strives to reduce its collective greenhouse gas emissions, New Hampshire's forests have the potential to offer another important advantage: a local renewable fuel source for electricity generation. As a founder and key participant in The Wood Energy Advisory Roundtable, PSNH works to ensure that the state's forests are protected while fulfilling this important new purpose.

> WORKING TOWARD A **SUSTAINABLE FUTURE**

Our commitment to supporting the region's growth requires an equally strong commitment to implementing sustainable solutions that meet the energy needs of today while protecting valuable resources for tomorrow. Achieving this balance requires an increased reliance on renewable energy sources, cleaner methods of energy production and sound strategies for energy efficiency and conservation.

Northeast Utilities is continuing to take noteworthy strides toward a sustainable energy future. PSNH's Northern Wood project, one of the country's largest renewable energy projects, completed its first year of operation. By replacing a 50 megawatt, coal-fired boiler at Schiller Station with an environmentally friendly wood-burning system, it allowed for the economic production of cleaner electric energy from a renewable resource. PSNH worked with New Hampshire environmental and forestry leaders on several initiatives to help ensure a continuous supply of wood from New Hampshire's forests while preserving the forest's benefits for future generations.

Renewable energy options such as wind and solar power are now available to Connecticut customers through CTCleanEnergyOptions, a program that enables customers to purchase their energy from a clean energy provider. PSNH encourages renewable energy investment with special incentives to customers who own a generator that uses a renewable energy source. WMECO customers will benefit from the company's support of research and development of renewable energy options and exploration of projects to demonstrate the effectiveness and environmental value of solar energy.

Energy efficiency and conservation programs are key elements of a sustainable future. In conjunction with the Connecticut Energy Efficiency Fund, the company's award-winning conservation and load management programs continue to deliver tangible benefits to customers. In focusing our attention on the future, we're bringing new energy-saving innovations to the market.

Energy efficiency incentive programs helped NU customers save nearly $370 million in electric energy costs and eliminate more than 1.7 million tons of carbon dioxide emissions over the past five years. With the help of PSNH, Southeastern Container, a manufacturer and supplier of plastic bottles to Coca-Cola, reduced energy consumption by 19 percent and saved $500,000 annually.

In Connecticut, CL&P worked with Stew Leonard's stores on a seven-year, energy efficiency program for its three Connecticut locations. Over the lifetime of the new technology, the stores will save 85 million kilowatt hours of electricity and avoid more than 46,000 tons of carbon dioxide emissions.

In demonstrating its commitment to the search for new solutions, NU sponsors the Northeast Energy Efficiency Partnership Summit, an annual meeting of leaders from multiple sectors to demonstrate the value of energy efficiency measures in supporting the region's economic growth and environmental goals. By assuming leadership roles like this, and through partnerships with advocacy groups like Environment Northeast, the Northeast Sustainable Energy Association and CERES, the Northeast Utilities companies remain on the leading edge of developing sustainable solutions for our energy future.

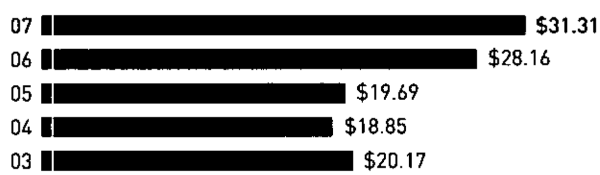
^ FINANCIAL **HIGHLIGHTS**

SELECTED FINANCIAL DATA

(Thousands of dollars, except share information and statistical data)	2007	2006
Operating Revenues	$5,822,226	$6,877,687
Operating Income	$ 539,481	$ 235,971
Net Income	$ 246,483	$ 470,578
Fully Diluted Earnings per Common Share	$ 1.59	$ 3.05
Fully Diluted Common Shares Outstanding (Weighted Average)	155,304,361	154,146,669
Dividends per Share	$ 0.775	$ 0.725
Sales of Electricity (Regulated Retail, KWH-millions)	36,142	35,620
Electric Customers (Average)	1,897,946	1,885,729
Gas Customers (Average)	202,743	199,377
Property, Plant and Equipment, Net	$7,229,945	$6,242,186
Market Capitalization as of Year End	$4,855,548	$4,343,205
Share Price as of Year End	$ 31.31	$ 28.16

DIVIDENDS PAID / SHARE For the Years Ended December 31.

CLOSING SHARE PRICE At Year End



SHARE PRICE PERFORMANCE

(Assumes $100 invested on December 31, 2002 in Northeast Utilities (NU) common shares, S&P 500 Index and S&P Electric Utilities Index with all dividends reinvested)

	2002	2003	2004	2005	2006	2007
S&P Electric Utilities	$100	$124	$157	$185	$228	$280
NU Common	**$100**	**$138**	**$133**	**$143**	**$212**	**$242**
S&P 500	$100	$129	$143	$150	$173	$183

> 2007 **FINANCIAL INFORMATION**

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the related notes included in this annual report. References in this exhibit to "NU" or "the company" are to Northeast Utilities, and the terms "we," "us" and "our" refer to NU. All per share amounts are reported on a fully diluted basis.

The only common equity securities that are publicly traded are common shares of NU. The earnings per share (EPS) of each segment hereinafter discussed does not represent a direct legal interest in the assets and liabilities allocated to such segment but rather represents a direct interest in our assets and liabilities as a whole. EPS by segment is a measure not recognized under accounting principles generally accepted in the United States of America (GAAP) that is calculated by dividing the net income or loss of each segment by the average fully diluted NU common shares outstanding for the period. We use this measure to provide segmented earnings guidance and believe that this measurement is useful to investors to evaluate the actual financial performance and contribution of our business segments. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of our operating performance.

The discussion below also references our earnings and EPS excluding non-cash, negative mark-to-market impacts on our competitive business, as well as charges from two significant, discrete impacts that occurred in 2006, which are the gain from the sale of our competitive generation business and a reduction in income tax expense pursuant to a Private Letter Ruling (PLR) issued by the Internal Revenue Service (IRS). We also discuss our operating cash flows excluding tax payments related to the sale of our competitive generation business. We use these non-GAAP measures to more fully explain and compare the 2007 and 2006 results without the impact of these non-cash or non-recurring items. These measures should not be considered as an alternative to our reported net income/(loss), EPS or operating cash flows determined in accordance with GAAP as an indicator of our operating performance.

Financial Condition and Business Analysis

Executive Summary

The following items in this executive summary are explained in more detail in this annual report:

Results, Strategy and Outlook:

- In 2007, we earned $246.5 million, or $1.59 per share, compared with earnings of $470.6 million, or $3.05 per share, in 2006. Results for 2006 included a significant, after-tax gain of $314 million, or $2.03 per share, associated with the sale of our competitive generation business and a reduction in income tax expense at The Connecticut Light and Power Company (CL&P) of $74 million, or $0.48 per share, pursuant to a PLR received from the IRS.

- Our regulated companies, which consist of CL&P, Public Service Company of New Hampshire (PSNH), Western Massachusetts Electric Company (WMECO) and Yankee Gas Services Company (Yankee Gas), earned $228.7 million, or $1.47 per share, in 2007, including $146.2 million, or $0.94 per share, in the distribution and generation segment (which includes the gas distribution segment of Yankee Gas) and $82.5 million, or $0.53 per share, in the transmission segment. In 2006, our distribution and generation segments earned $197.5 million, or $1.28 per share. Excluding the aforementioned reduction in CL&P's tax expense, the distribution and generation segment earned $123.5 million, or $0.80 per share, in 2006. The transmission segments of CL&P, PSNH and WMECO earned $59.8 million, or $0.39 per share, in 2006.

- NU Enterprises, Inc. (NU Enterprises) earned $11.7 million in 2007, or $0.08 per share, compared with earnings of $211.3 million, or $1.37 per share, in 2006. Excluding NU Enterprises' portion of the gain on the sale of our competitive generation business in 2006 and the negative mark-to-market impacts of $3.8 million and $14.8 million in 2007 and 2006, respectively, NU Enterprises earned $15.5 million, or $0.10 per share in 2007, and incurred losses of $80.8 million, or $0.52 per share, in 2006.

- NU parent and other companies earned $6.1 million, or $0.04 per share, in 2007, compared with earnings of $2 million, or $0.01 per share, in 2006.

- In 2007, Yankee Gas completed the construction and the initial filling of a $108 million, liquefied natural gas (LNG) storage and production facility in Waterbury, Connecticut, which is capable of storing the equivalent of 1.2 bcf of natural gas.

- CL&P has currently completed the majority of each of its three major transmission projects presently under construction in southwest Connecticut. Two of those projects are expected to be completed in 2008 and the third in 2009.

- We project consolidated 2008 earnings of between $1.65 per share and $1.90 per share, including earnings of between $1.05 per share and $1.15 per share at our distribution and generation segments and between $0.75 per share and $0.85 per share at our transmission segments. We also project breakeven results in our remaining competitive businesses and a loss of between $0.10 per share and $0.15 per share for NU parent and other companies.

- We project that we can achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent for the period 2008 through 2012, with 2007 EPS of $1.59 as the base year. This growth rate assumes that we meet our capital investment and rate base projections and that we receive appropriate regulatory approvals, allowed returns and timely rate treatment for those investments.

Legislative, Legal and Regulatory Items:

- On January 28, 2008, the Connecticut Department of Public Utility Control (DPUC) approved $77.8 million, or 11.7 percent, and $20.1 million, or 2.6 percent, in annualized increases over CL&P's current distribution rates, effective on February 1, 2008 and 2009, respectively, which also represents a 0.9 percent increase on a total rates basis over December 2007 rates and a 0.4 percent increase on a total rates basis over February 2008 rates, respectively. The rate decision included a regulatory return on equity (Regulatory ROE) of 9.4 percent, which was significantly lower than CL&P's requested amount, and the approval of substantially all of CL&P's requested distribution segment capital program of $294 million for 2008 and $288 million for 2009. Due to the disallowance of certain operating expenses in rates, we project CL&P's Regulatory ROE for 2008 to be lower than the authorized amount.

- On June 29, 2007, the DPUC approved a rate case settlement agreement between Yankee Gas, the Connecticut Office of Consumer Counsel (OCC) and the DPUC's Prosecutorial Division that resulted in an annualized increase of $22.1 million, or 4.2 percent, in Yankee Gas's base rates effective on July 1, 2007. The settlement agreement, among other terms, provided for recovery of costs associated with Yankee Gas's LNG storage and production facility.

- On May 25, 2007, the New Hampshire Public Utilities Commission (NHPUC) approved a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the New Hampshire Office of Consumer Advocate (OCA). The settlement agreement allowed for a $37.7 million estimated annualized rate increase beginning on July 1, 2007, along with the previous $24.5 million annualized temporary distribution rate increase that was effective on July 1, 2006. The $37.7 million includes a one-year revenue increase of approximately $9 million related to additional revenues to recoup the difference between the temporary and permanent rates for the period of July 1, 2006 through June 30, 2007. An additional delivery revenue increase of $3 million took effect on January 1, 2008, with a final estimated rate decrease of approximately $9 million scheduled for July 1, 2008. The settlement also provided for a tracking mechanism which allows PSNH to recover retail transmission costs on a timely basis.

- In accordance with the two-year settlement that was implemented on January 1, 2007, WMECO's distribution rates increased by $3 million on January 1, 2008.

- On June 4, 2007, Connecticut Governor Rell signed into law "An Act Concerning Electricity and Energy Efficiency" (Energy Efficiency Act). Among other provisions, the Energy Efficiency Act requires electric distribution companies to file integrated resource plans for DPUC approval, provides incentives for customers to reduce consumption, particularly during peak load periods, and requires CL&P and The United Illuminating Company (UI) to file proposals with the DPUC to build cost-of-service peaking generation facilities.

- On January 31, 2008, the trial judge in our ongoing litigation with Consolidated Edison, Inc. (Con Edison) in connection with our October 13, 1999 Agreement and Plan of Merger, denied a series of motions by both us and Con Edison that had been pending for more than one year, including our motion for an order dismissing Con Edison's claim for damages. The judge ordered the parties to be trial ready on four days' notice beginning March 21, 2008. It is not possible for us to predict either the outcome of this matter or its ultimate effect on us.

Liquidity:

- Our liquidity position benefited from the proceeds we received from the sale of NU Enterprises' competitive generation assets in November of 2006 and the issuance of $655 million of long-term debt in 2007 by our regulated companies.

- Our cash capital expenditures totaled $1.1 billion in 2007, compared with $872.2 million in 2006, most of which was incurred by our regulated companies in both years. The increase was primarily the result of higher transmission capital expenditures, particularly at CL&P. Our cash capital expenditures in 2007 included $826.2 million by CL&P, $167.7 million by PSNH, $47.3 million by WMECO, $57.6 million by Yankee Gas, and $16 million by other NU subsidiaries.

- We project a total of approximately $6 billion of regulated company capital expenditures from 2008 through 2012, including $1.3 billion in 2008. Over the five-year period, approximately $3 billion is projected to be spent on transmission and $3 billion on distribution and generation. In 2008, approximately $700 million is expected to be spent on transmission and $600 million on distribution and generation.

- We had consolidated operating cash flows in 2007 of $248.4 million, compared with $407.1 million in 2006. Excluding the federal and state income tax payments of approximately $400 million in 2007 related to the 2006 sale of the competitive generation business, our consolidated operating cash flows were approximately $650 million in 2007, which is an increase of approximately $243 million from 2006. This improvement was partially due to an expected reduction in regulatory refunds paid to CL&P customers during 2007 as compared to 2006. In addition, the regulated companies made lower payments to Connecticut Yankee Atomic Power Company (CYAPC), Maine Yankee Atomic Power Company (MYAPC) and Yankee Atomic Electric Company (YAEC) (the Yankee Companies) for nuclear decommissioning and closure costs in 2007 as compared to 2006. Also impacting cash flows from operations were lower cash payments related to Select Energy, Inc.'s (Select Energy) derivative contracts and changes in working capital items related to the divestiture of NU Enterprises' businesses in 2006.

- We had $15.1 million of cash and cash equivalents on hand at December 31, 2007, compared with $481.9 million at December 31, 2006, due to a decline in our cash position from funding our capital expenditures program and the payment of approximately $400 million in federal and state income taxes in 2007, as described above.

Overview

Consolidated: We earned $246.5 million, or $1.59 per share, in 2007, compared with earnings of $470.6 million, or $3.05 per share, in 2006, and a loss of $253.5 million, or $1.93 per share, in 2005. Results for 2006 included a significant, after-tax gain of $314 million, or $2.03 per share, associated with the sale of our competitive generation business and a reduction in income tax expense at CL&P of $74 million, or $0.48 per share, pursuant to a PLR received from the IRS. Results in 2007 and 2006 included discretionary pre-tax donations to the NU Foundation, Inc. (Foundation) of $3 million and $25 million, respectively. In 2005, our competitive businesses incurred a significant loss due primarily to mark-to-market changes in the fair value of NU Enterprises' wholesale marketing contracts. Since 2005, we have divested most of our competitive businesses.

A summary of our earnings/(losses) by segment for 2007, 2006 and 2005 is as follows (millions of dollars, except per share amounts):

	For the Years Ended December 31,					
	2007		2006		2005	
Segment	Amount	Per Share	Amount	Per Share	Amount	Per Share
Regulated companies	$228.7	$1.47	$257.3	$1.67	$ 163.4	$ 1.24
NU Enterprises	11.7	0.08	211.3	1.37	(398.2)	(3.03)
NU parent and other companies	6.1	0.04	2.0	0.01	(18.7)	(0.14)
Net Income/(Loss)	$246.5	$1.59	$470.6	$3.05	$(253.5)	$(1.93)

Regulated Companies: Our regulated companies, which are comprised of CL&P, PSNH, WMECO and Yankee Gas, segment their earnings between their electric transmission segments and their electric and gas distribution segments, with PSNH generation included with its distribution segment. A summary of regulated company earnings by segment for 2007, 2006 and 2005 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2007	2006	2005
CL&P Transmission*	$ 66.7	$ 46.9	$ 29.3
PSNH Transmission	10.7	8.3	7.8
WMECO Transmission	5.1	4.6	4.0
Total Transmission	$ 82.5	$ 59.8	$ 41.1
CL&P Distribution*	$ 61.4	$147.6	$ 60.0
PSNH Distribution and Generation	43.7	27.0	33.9
WMECO Distribution	18.5	11.0	11.1
Yankee Gas	22.6	11.9	17.3
Total Distribution and Generation	$146.2	$197.5	$122.3
Net Income – Regulated Companies	$228.7	$257.3	$163.4

*After preferred dividends in all years.

The increases in transmission segment earnings in 2007 reflect a reduction in 2006 fourth quarter earnings as a result of the October 31, 2006 Federal Energy Regulatory Commission (FERC) Return on Equity (ROE) decision and a higher FERC-approved ROE for 2007. Additionally, for both 2007 and 2006, earnings increases reflect a higher level of investment in our transmission infrastructure, particularly at CL&P, where we have invested approximately $1 billion since the beginning of 2005. This investment has been made primarily to upgrade the transmission infrastructure of southwest Connecticut. At December 31, 2007, CL&P's transmission rate base was approximately $1.2 billion. Under the company's transmission tariffs, our transmission segment earnings generally track with the level of rate base.

CL&P's 2007 distribution segment earnings were $86.2 million lower than in 2006 primarily because of the $74 million reduction in income tax expense pursuant to the PLR received from the IRS in 2006 related to the treatment of excess deferred income taxes (EDIT) and unamortized tax credits in connection with the sale of CL&P's former generating plants. Excluding the impact of the PLR on 2006 earnings, CL&P's 2007 distribution segment earnings were $12.2 million lower than in 2006. This decrease in earnings was primarily due to the $7.7 million after-tax benefit in 2006 related to the sale to a third party of competitive generation assets that CL&P had previously sold to its affiliate, Northeast Generation Company (NGC); the absence in 2007 of a fixed procurement fee of approximately $6.6 million (after-tax) that expired at the end of 2006; higher operations and maintenance expense; higher interest expense; and higher income tax expense, partially offset by a $7 million distribution rate increase that took effect on January 1, 2007 and a 1.7 percent increase in sales. CL&P's distribution segment Regulatory ROE was 7.9 percent for 2007 and 7.5 percent for 2006.

We expect CL&P's distribution segment Regulatory ROE will be in the 8 percent to 8.5 percent range in the first full year of new rates beginning February 1, 2008 as a result of the DPUC's final decision in CL&P's distribution rate proceeding. Due to the February 2008 implementation of new rates, we expect a CL&P distribution segment Regulatory ROE of approximately 8 percent in calendar year 2008.

PSNH's distribution and generation segment earnings in 2007 were $16.7 million higher than in 2006 primarily due to a $24.5 million annualized temporary rate increase that took effect on July 1, 2006; a $37.7 million annualized energy delivery rate increase that took effect on July 1, 2007; recovery of approximately $4.5 million of pre-tax retail transmission costs that were expensed in 2006; the implementation of a retail transmission cost tracking mechanism; and lower unitary state income taxes. These increases were partially offset by higher operations and maintenance expense, higher depreciation, and higher interest expense. PSNH's distribution and generation segment Regulatory ROE was 9.5 percent in 2007 and 6.4 percent in 2006. We expect PSNH's distribution and generation segment Regulatory ROE to be towards the low end of a 9 percent to 10 percent range at approximately 9 percent in 2008.

WMECO's distribution segment earnings in 2007 were $7.5 million higher than in 2006 primarily due to the impacts of a rate settlement that became effective on January 1, 2007. The settlement included, among other things, a $1 million annualized rate increase and the implementation of several cost tracking mechanisms. The 2007 earnings also did not include certain charges that negatively impacted us in 2006. Higher earnings were partially offset by higher depreciation expense. WMECO's distribution segment Regulatory ROE was approximately 9.7 percent in 2007 and 9.6 percent in 2006. We expect WMECO's distribution segment Regulatory ROE to be towards the low end of a 9 percent to 10 percent range at approximately 9 percent in 2008.

Yankee Gas's 2007 earnings improved significantly from 2006 due to a $22.1 million net annualized distribution rate increase that took effect on July 1, 2007 and a 10.3 percent increase in firm natural gas sales primarily due to unseasonably warm weather in the early and late months of 2006. Partially offsetting the rate increase and increase in sales were higher operations and maintenance expense and higher interest, depreciation and income tax expense. Yankee Gas's Regulatory ROE was 8.7 percent for 2007 and 5.9 percent in 2006. We expect Yankee Gas's Regulatory ROE to be at the mid-to-higher end of a 9 percent to 10 percent range in 2008.

For the distribution segment of the regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric kilowatt-hour (KWH) sales and Yankee Gas firm natural gas sales for 2007 as compared to 2006 on an actual and weather normalized basis (using a 30-year average) is as follows:

	Electric								Firm Natural Gas	
	CL&P		PSNH		WMECO		Total		Yankee Gas	
	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase/ (Decrease)	Weather Normalized Percentage Increase/ (Decrease)	Percentage Increase	Weather Normalized Percentage Increase/ (Decrease)
Residential	2.8 %	0.4 %	2.9 %	1.5 %	1.9 %	(0.3)%	2.7 %	0.6 %	17.0%	6.6 %
Commercial	1.3 %	0.8 %	1.8 %	1.6 %	1.0 %	0.5 %	1.5 %	1.0 %	12.1%	3.1 %
Industrial	(1.3)%	(1.5)%	(3.4)%	(3.2)%	(2.3)%	(2.4)%	(2.0)%	(2.1)%	1.9%	(0.6)%
Other	6.9 %	6.9 %	4.9 %	4.9 %	—	—	6.2 %	6.2 %	—%	— %
Total	1.7 %	0.4 %	1.2 %	0.6 %	0.6 %	(0.4)%	1.5 %	0.4 %	10.3%	3.1 %

A summary of our retail electric sales in gigawatt hours for CL&P, PSNH and WMECO, and firm natural gas sales in million cubic feet for Yankee Gas for 2007 and 2006 is as follows:

	Electric			Firm Natural Gas		
	2007	2006	Percentage Increase/ (Decrease)	**2007**	2006	Percentage Increase
Residential	**15,051**	14,652	2.7 %	**13,742**	11,743	17.0%
Commercial	**15,103**	14,886	1.5 %	**12,965**	11,562	12.1%
Industrial	**5,635**	5,750	(2.0)%	**12,193**	11,971	1.9%
Other	**353**	332	6.2 %	**—**	—	—%
Total	**36,142**	35,620	1.5 %	**38,900**	35,276	10.3%

Our electric sales per customer, adjusted for weather impacts, have been negatively affected by retail rate increases driven by the energy component of customer bills that began in early 2006. Although the longer-term trend in customer usage in our service territory when energy prices were stable had reflected a generally increasing use per customer, customers have responded to higher energy prices in recent years by using less electricity. Even though generation costs stabilized in 2007, use per customer on a weather normalized basis did not change significantly from 2006 levels, reflecting continued conservation efforts. We cannot determine at this time whether these trends will continue or the effect they may have on our distribution segment earnings.

NU Enterprises: NU Enterprises continues to manage to completion its remaining wholesale marketing contracts and energy services activities.

Our consolidated statements of income/(loss) for the years ended December 31, 2007, 2006 and 2005 classify the following as discontinued operations:

- NGC, including certain components of Northeast Generation Services Company,
- The Mt. Tom generating plant (Mt. Tom) previously owned by Holyoke Water Power Company (HWP),
- Select Energy Services, Inc. (SESI) and its wholly-owned subsidiaries HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC,
- A portion of the former Woods Electrical Co., Inc. (Woods Electrical)
- Select Energy Contracting, Inc. (including Reeds Ferry Supply Co., Inc.) (SECI), and
- Woods Network Services, Inc. (Woods Network).

NU Enterprises earned $11.7 million in 2007 on revenues of $97.7 million, compared with $211.3 million in 2006 on revenues of $901.8 million, and a loss of $398.2 million in 2005 on revenues of $1.9 billion. NU Enterprises' results for the past three years have been significantly affected by our decision in 2005 to divest our competitive businesses. NU Enterprises' earnings in 2007 were primarily the result of higher than expected margins and the favorable resolution of certain legal and contract issues, partially offset by the $3.8 million ($6.4 million pre-tax) negative impact of mark-to-market charges on the remaining wholesale marketing contracts.

NU Enterprises' higher earnings in 2006 were attributable to the after-tax gain on the sale of the competitive generation business, partially offset by $70.3 million of losses at NU Enterprises' retail marketing segment, which was sold on June 1, 2006. The significant loss in 2005 was primarily attributable to pre-tax mark-to-market charges of $425.4 million on NU Enterprises' wholesale marketing contracts. As of December 31, 2007, the majority of NU Enterprises' wholesale marketing contracts had either expired or been divested. NU Enterprises' remaining two wholesale marketing sales contracts and related sourcing contracts have been marked to market and, based on current market prices, will have a moderately negative impact on cash flows until they expire in 2008 and 2013. NU Enterprises' only other remaining contract is a wholesale purchase contract that expires in 2012, which is not marked to market.

NU Parent and Other Companies: NU parent and other companies earned $6.1 million, or $0.04 per share, in 2007, compared with earnings of $2 million, or $0.01 per share, in 2006, and a loss of $18.7 million, or $0.14 per share, in 2005. The improvement in 2007 results compared with 2006 and 2005 was due to higher interest income earned on cash balances that NU companies borrowed from NU parent through the NU Money Pool (Pool) or that NU parent invested in outside money market funds. Earnings on Pool investments are eliminated in consolidation along with the corresponding interest expense for the Pool borrowers. Management expects that NU parent earnings will decline in 2008, since NU parent's cash has been used to make equity investments in the regulated companies to support capital expenditures.

Future Outlook

We project consolidated 2008 earnings of between $1.65 per share and $1.90 per share.

Regulated Companies: We project 2008 earnings of between $1.05 per share and $1.15 per share for the distribution and generation segment and between $0.75 per share and $0.85 per share for the transmission segment.

NU Parent and Other Companies: We project a loss of between $0.10 per share and $0.15 per share in 2008 for NU parent and other companies. NU parent net interest expense is expected to increase due to the decrease in NU's cash investments.

NU Enterprises: We project approximately breakeven results in 2008 for NU Enterprises. For information regarding sensitivity analyses of NU Enterprises' remaining wholesale contracts, see Item 7.A., "Quantitative and Qualitative Disclosures About Market Risk," included in our report on Form 10-K.

Long-Term Growth Rate: We project that we can achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent for the period 2008 through 2012, with 2007 EPS of $1.59 as the base year. This growth rate assumes that we meet our capital investment and rate base projections and that we receive appropriate regulatory approvals, allowed returns and timely rate treatment for those investments. We currently expect transmission segment earnings to be approximately 50 percent of total earnings by 2012.

Liquidity

Consolidated: During 2007, our liquidity position benefited from the proceeds we received from the sale of NU Enterprises' competitive generation assets in November of 2006 and the issuance of $655 million of long-term debt by the regulated companies, including $45 million in long-term borrowings under the regulated companies' revolving credit line. At December 31, 2007, NU parent had $27 million of letters of credit (LOC) issued and $42 million borrowed under its $500 million revolving credit line. At December 31, 2007, the regulated companies had $37 million of short-term debt borrowed under their $400 million revolving credit line, and CL&P had $20 million sold under its $100 million facility for the sale of accounts receivable.

We had $15.1 million of cash and cash equivalents on hand at December 31, 2007, compared with $481.9 million at December 31, 2006. The decline primarily resulted from funding our capital expenditure program in 2007 and the payment of approximately $400 million in federal and state income taxes in 2007 related to the 2006 sale of the competitive generation business. CL&P and WMECO accrued the majority of their portions of these tax obligations in 2000 upon the sale of their generation assets to NGC, but due to the intercompany nature of the sales, the federal and state income tax payments were deferred at that time. It was not until we sold NGC to an unaffiliated third party in November of 2006 that CL&P and WMECO were required to pay these taxes.

We had consolidated operating cash flows in 2007 of $248.4 million, compared with $407.1 million in 2006 and $441.2 million in 2005. Excluding the federal and state income tax payments of approximately $400 million in 2007 related to the 2006 sale of the competitive generation business, our consolidated operating cash flows were approximately $650 million in 2007, which was an increase of approximately $243 million from 2006. This improvement was partially due to an expected reduction in regulatory refunds related to Competitive Transition Assessment (CTA) made to CL&P customers during 2007 as compared to 2006. In addition to lower regulatory refunds paid, the regulated companies made lower payments to the Yankee Companies for nuclear decommissioning and closure costs in 2007 as compared to 2006, primarily as a result of the extension of the collection period for decommissioning and closure costs at CYAPC. Also impacting cash flows from operations were lower cash payments related to Select Energy's derivative contracts and changes in working capital items related to the divestiture of NU Enterprises' businesses in 2006. In 2008, we project consolidated operating cash flows of approximately $500 million, rising to between approximately $800 million and $850 million in 2012. These projections assume that we receive timely recovery of our capital investments and purchased power costs through appropriate rates.

All four of the regulated companies issued long-term debt in 2007. CL&P issued $500 million of first mortgage bonds, PSNH issued $70 million of first mortgage bonds, WMECO issued $40 million of unsecured notes and Yankee Gas borrowed $45 million for a 30-month term under the regulated companies' revolving credit facility. The fixed rate securities were issued for terms of 10 years and 30 years with coupons ranging from 5.375 percent to 6.7 percent.

In 2008, we expect that NU parent, CL&P, PSNH and Yankee Gas will issue a total of approximately $700 million of long-term debt. Most of the debt will be issued by the regulated companies to finance their capital programs. NU parent plans to issue up to $200 million of debt, primarily to refinance $150 million of senior notes that mature on June 1, 2008 and are included in long-term debt – current portion on the accompanying consolidated balance sheet at December 31, 2007.

A summary of the current credit ratings and outlooks by Moody's Investors Service (Moody's), Standard & Poor's (S&P) and Fitch Ratings (Fitch) for NU parent and WMECO's senior unsecured debt and CL&P and PSNH's first mortgage bonds is as follows:

	Moody's		S&P		Fitch	
	Current	Outlook	Current	Outlook	Current	Outlook
NU Parent	Baa2	Stable	BBB-	Stable	BBB	Stable
CL&P	A3	Stable	BBB+	Stable	A-	Stable
PSNH	Baa1	Stable	BBB+	Stable	BBB+	Stable
WMECO	Baa2	Stable	BBB	Stable	BBB+	Stable

All three rating agencies reaffirmed their credit ratings for NU parent, CL&P, PSNH and WMECO in 2007. The only credit ratings change in 2007 occurred when, as part of a comprehensive reassessment of utility secured debt ratings, S&P raised PSNH's secured debt ratings by one notch to BBB+.

If NU parent's senior unsecured debt ratings were to be reduced to a sub-investment grade level by either Moody's or S&P, Select Energy could, under its remaining contracts, be required to provide collateral or LOCs in the amount of approximately $70.4 million to various unaffiliated counterparties and collateral or LOCs in the amount of approximately $23.4 million to several independent system operators and unaffiliated local distribution companies (LDCs) at December 31, 2007. If such a downgrade were to occur, NU parent would currently be able to provide that collateral.

NU parent last issued common equity in December of 2005 when it sold 23 million common shares at a price of $19.09 per share. Proceeds from that issuance, from the sale of our competitive generation assets, and from the issuance of regulated company long-term debt were utilized to fund the regulated companies' capital programs in 2006 and 2007. We expect further debt issuances and growth in operating cash flows will finance our 2008 capital program. We also believe that we can maintain our existing credit ratings and access to debt capital. At December 31, 2007, our ratio of consolidated total debt to total capitalization was 54.6 percent. To maintain those credit metrics, NU parent expects to issue approximately $500 million of equity from 2009 through 2012 with approximately half of that amount expected to be issued in 2009 and the remainder expected to be issued later in the period.

NU parent paid common dividends of $121 million in 2007, compared with $112.7 million in 2006 and $87.6 million in 2005. The increase in common dividends paid from 2005 to 2007 reflects a 7.1 percent increase in the amount of NU parent's common dividend that took effect in the third quarter of 2006 and another 6.7 percent increase that took effect in the third quarter of 2007, as well as a higher number of shares outstanding in 2007 and 2006 as a result of NU parent's common share issuance in December of 2005. On February 12 2008, our Board of Trustees approved a quarterly dividend of $0.20 per share, or $0.80 per share on an annualized basis, payable on March 31, 2008 to shareholders of record as of March 1, 2008.

We expect to continue our current policy of dividend increases, subject to the approval of our Board of Trustees and our future earnings and cash requirements. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In 2007, CL&P, PSNH, WMECO, and Yankee Gas paid $79.2 million, $30.7 million, $12.8 million, and $12.7 million, respectively, in common dividends to NU parent. In 2007, NU parent contributed $570.7 million of equity to CL&P, $44.2 million to PSNH, $13.6 million to WMECO and $52.8 million to Yankee Gas. At December 31, 2007, NU parent had $44.1 million invested in the Pool and will continue to infuse equity into the regulated companies as their capital needs and structure dictate. At December 31, 2007, the Pool had a balance of $0.6 million invested externally.

NU parent's ability to pay dividends may be affected by certain state statutes, the leverage restrictions in its revolving credit agreement and the ability of its subsidiaries to pay dividends to it. The Federal Power Act limits, unless a higher amount is approved by the FERC, the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances, and PSNH is required to reserve an additional amount under certain FERC hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also have a leverage restriction under their revolving credit agreement.

Cash capital expenditures included on the accompanying consolidated statements of cash flows and described in the liquidity section of this management's discussion and analysis do not include amounts incurred but not paid, cost of removal, the allowance for funds used during construction (AFUDC) related to equity funds, and the capitalized portion of pension expense or income. Our cash capital expenditures totaled $1.1 billion in 2007, compared with $872.2 million in 2006, most of which was incurred by our regulated companies in both years. Our cash capital expenditures in 2007 included $826.2 million by CL&P, $167.7 million by PSNH, $47.3 million by WMECO, $57.6 million by Yankee Gas, and $16 million by other NU subsidiaries. In 2006, cash capital expenditures included $567.2 million by CL&P; $126.7 million by PSNH; $42.8 million by WMECO; $87.6 million by Yankee Gas, and $47.9 million by other NU subsidiaries. The increase in the regulated companies' cash capital expenditures was primarily the result of higher transmission capital expenditures, particularly at CL&P.

Regulated Companies: The regulated companies maintain a $400 million credit facility that expires on November 6, 2010. There were $45 million of long-term borrowings by Yankee Gas outstanding under that facility at December 31, 2007. In addition, there were $10 million and $27 million in short-term borrowings by PSNH and Yankee Gas, respectively, outstanding under this facility at December 31, 2007. The weighted-average interest rate on these short-term borrowings at December 31, 2007 was 7.25 percent.

In addition to this revolving credit facility, CL&P has an arrangement with a financial institution under which CL&P can sell up to $100 million of its accounts receivable and unbilled revenues. There was $20 million sold under that facility at December 31, 2007. For more information regarding CL&P's sale of receivables, see Note 1L, "Summary of Significant Accounting Policies – Sale of Customer Receivables," to the consolidated financial statements.

Impact of Credit Markets: As previously discussed, we plan to issue approximately $700 million of long-term debt in 2008 and have entered into forward interest rate swaps to hedge exposure to market rates for these planned issuances. Due to the overall uncertainties in the market, however, the credit spreads on these issuances may be higher than we have experienced in the past. We believe that the credit markets will continue to be supportive of our debt issuances and that, despite volatility in treasury rates and credit spreads, we will be able to issue this debt at competitive rates.

Certain bond insurers have experienced increasing ratings pressure and are on negative watch by the credit rating agencies. Credit ratings of certain of our Pollution Control Revenue Bonds (PCRBs) are enhanced with bond insurance. We do not expect the financial condition of the bond insurers to have a material impact on us, although concerns regarding the bond insurers' credit strength could increase interest expense associated with $151 million of PCRBs that we may remarket in 2008. PSNH has $89 million of PCRBs that have a variable rate. We are considering fixing this rate through the 2021 maturity date of the bonds. CL&P has $62 million of PCRBs with a fixed rate through October 1, 2008. We will consider fixing the interest rate on these bonds at that time.

NU Enterprises: The working capital and LOCs required by NU Enterprises are currently used to support Select Energy's remaining wholesale contracts. As these wholesale contracts expire or are exited, NU Enterprises' liquidity requirements will continue to decline.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income, totaled $1.3 billion in 2007, compared with $945.8 million in 2006 and $814.3 million in 2005. These amounts include $16 million, $17.6 million and $25.6 million in 2007, 2006 and 2005, respectively, that related to our corporate service company and other affiliated companies that support the regulated companies.

Regulated Companies:

We project a total of approximately $6 billion of regulated company capital expenditures from 2008 through 2012, which also includes amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income (all of which are predominantly non-cash factors in determining rate base). A summary of these estimated capital expenditures for the regulated companies' transmission segment and distribution and generation segments by company for 2008 through 2012, including corporate service companies' capital expenditures on behalf of the regulated companies, is as follows (millions of dollars):

	Year					
	2008	2009	2010	2011	2012	Totals
CL&P:						
Transmission	$ 538	$ 311	$155	$ 420	$ 530	$1,954
Distribution	334	291	289	298	297	1,509
PSNH:						
Transmission	108	58	55	108	72	401
Distribution and generation	167	143	153	172	252	887
WMECO:						
Transmission	50	137	222	135	104	648
Distribution	35	40	34	34	34	177
Yankee Gas:						
Distribution	56	60	60	61	68	305
Totals – Transmission	696	506	432	663	706	3,003
Totals – Distribution and generation	592	534	536	565	651	2,878
Corporate service companies	22	28	18	19	14	101
Totals	$1,310	$1,068	$986	$1,247	$1,371	$5,982

CL&P's distribution capital expenditures will primarily address its aging distribution infrastructure, and increase reliability and system capacity. Costs of these capital expenditures have increased from prior years due to higher costs for transformers, cables, conductors, and other materials.

The significant increase in capital spending at PSNH in 2011 and 2012 reflects the planned installation of a wet scrubber at PSNH's coal-fired 440-megawatts (MW) Merrimack Station to reduce mercury and sulfur emissions. As a result of 2006 state legislation, PSNH must complete installation of that scrubber by July 1, 2013. PSNH expects that the full estimated cost of $250 million for that installation will be recoverable through PSNH's energy rate.

Actual levels of capital expenditures could vary from the estimated amounts for the companies and periods above. Based on these estimated capital expenditures, we project our transmission and distribution and generation rate base at December 31st of each year will be as follows (millions of dollars):

	Year				
	2008	2009	2010	2011	2012
CL&P:					
Transmission	$1,763	$2,168	$2,199	$2,515	$2,828
Distribution	2,130	2,296	2,450	2,584	2,705
PSNH:					
Transmission	295	306	367	371	458
Distribution and generation	1,078	1,176	1,251	1,326	1,408
WMECO:					
Transmission	114	242	422	549	606
Distribution	396	423	448	474	503
Yankee Gas:					
Distribution	693	728	748	773	806
Totals – Transmission	2,172	2,716	2,988	3,435	3,892
Totals – Distribution and generation	4,297	4,623	4,897	5,157	5,422
Totals	$6,469	$7,339	$7,885	$8,592	$9,314

Several factors may impact the regulated companies' rate base amounts above, including the level and timing of capital expenditures and plant placed in service, regulatory approval of rate increases and other factors.

Transmission Segment: Our transmission rate base totaled approximately $1.5 billion at December 31, 2007, including approximately $0.3 billion of incurred construction costs, or construction work in progress (CWIP), compared with approximately $1.0 billion at December 31, 2006, including approximately $0.1 billion of CWIP. In addition, the transmission segment recorded $406 million and $162 million of CWIP at December 31, 2007 and 2006, respectively, that were not in rate base. The projected transmission rate base amounts reflected above include CWIP for 50 percent of the southwest Connecticut projects (Middletown to Norwalk, Connecticut; Norwalk to Stamford, Connecticut; and Norwalk, Connecticut to Northport-Long Island, New York) and, assuming FERC will allow related CWIP in rate base, 100 percent of the New England East-West (NEEWS) 345 kilovolt (KV) and 115 KV Overhead projects and the 115 KV Springfield Underground Cables project referred to below. The CWIP amounts included in rate base for these projects are $242 million, $124 million, $238 million, $437 million, and $450 million, respectively, for the 2008 to 2012 periods.

A summary of transmission segment capital expenditures by company in 2007, 2006 and 2005 is as follows (millions of dollars):

	For the Years Ended December 31,		
	2007	2006	2005
CL&P	**$660.6**	$415.6	$215.3
PSNH	**80.7**	36.1	28.5
WMECO	**19.3**	13.0	12.9
Other	**1.2**	0.8	0.6
Totals	**$761.8**	$465.5	$257.3

The increases in transmission segment capital expenditures in 2007 as compared with 2006 and 2005 primarily relate to CL&P, which is undertaking a significant enhancement of its transmission system in southwest Connecticut. CL&P completed one major transmission project, the 21-mile 345 KV/115 KV transmission project between Bethel, Connecticut and Norwalk, Connecticut, in 2006 and has three major projects currently under construction in southwest Connecticut, including:

- A 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut. CL&P's portion of this project is estimated to cost approximately $1.05 billion. At December 31, 2007, CL&P's portion of this project was approximately 62 percent complete and by the end of February of 2008, was approximately 70 percent complete. As of December 31, 2007, CL&P had capitalized $593 million associated with this project. Although the project is scheduled to be completed at the end of 2009, construction of the project is currently ahead of schedule, and CL&P has reviewed the remaining work to determine whether it can be completed at an earlier date. As a result of this review, we now expect to complete this project in mid-2009. This early completion date would not have a significant impact on our earnings guidance.
- A two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), construction of which began in October of 2006. This project is estimated to cost approximately $223 million. This project is scheduled to be completed by the end of 2008. At December 31, 2007, this project was approximately 69 percent complete, and at the end of February of 2008, was approximately 74 percent complete As of December 31, 2007, CL&P had capitalized $133 million associated with this project.
- The replacement of the 138 KV, 11-mile undersea electric transmission cable between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable). CL&P and the Long Island Power Authority each own approximately 50 percent of the line. CL&P's portion of the project is estimated to cost $72 million. After the final regulatory permits were received, marine construction activities commenced in October of 2007, and the project is expected to be placed in service in the second half of 2008. The pre-existing cables were decommissioned in September of 2007, and approximately 94 percent of the cables was removed as of December 31, 2007, including all portions located in Connecticut. Installation of the new cable began in early February of 2008. At December 31, 2007, the project was approximately 63 percent complete, and at the end of February of 2008, was approximately 72 percent complete. As of December 31, 2007, CL&P had capitalized $45 million associated with this project, including the cost of the new cable, which was delivered in the fourth quarter of 2007.

In addition to our current transmission construction in southwest Connecticut, we continue to work with ISO-NE to refine the design criteria of our next series of major transmission projects: (i) the New England East-West 345 KV and 115 KV Overhead project (NEEWS Overhead project) and (ii) the 115 KV Springfield Underground Cables project (Springfield Underground Cables project).

The NEEWS Overhead project includes three 345 KV transmission upgrades that will collectively address the region's transmission needs and better connect the major east-west transmission interfaces in Southern New England: 1) the Greater Springfield 345 KV Reliability Project, 2) the Central Connecticut Reliability Project, and 3) the Interstate Reliability Project. A fourth upgrade, National Grid's Rhode Island Reliability Project, is also included in the NEEWS Overhead project. In early 2007, we entered into a formal agreement with National Grid to plan and permit these projects and expect the ISO-NE technical review process with respect to the NEEWS Overhead project to conclude by mid- to late- 2008. We will make the filing of the first project applications with the various state siting authorities shortly after receiving the technical approvals from ISO-NE. We continue to work with ISO-NE to ensure that the design of these projects balances needs and reliability, operational flexibility, and cost. At this time, we expect the siting process for the NEEWS Overhead project to be completed by 2010 and to complete construction in 2013. We have not yet updated our detailed estimate of the total cost for the NEEWS Overhead project, and the timing of expenditures is highly dependent upon receipt of technical and siting approvals.

The second major transmission project, the Springfield Underground Cables project, consists of a significant upgrade of the 115 KV electrical system around Springfield, Massachusetts to address thermal overload and voltage issues. WMECO received a favorable vote from the ISO-NE Reliability Committee regarding the project's technical feasibility in December 2007, and WMECO filed the siting application immediately thereafter with the Massachusetts siting agencies. We expect the siting process to be completed in 2009 and expect WMECO to complete the project by the end of 2011.

Assuming that virtually all of the 345 KV portions of the NEEWS Overhead project are constructed overhead and on existing rights of way, we are maintaining our estimate of our share of the cost of the NEEWS Overhead project at approximately $1.05 billion. We are also maintaining our estimate of the cost of the Springfield Underground Cables project at approximately $350 million at this time. However, as we continue to review the designs of the NEEWS Overhead project and the Springfield Underground Cables project with ISO-NE over the coming months, we expect these figures to change. We anticipate that we will have additional information on the scope and costs of these projects by mid-2008.

In October of 2006, the Bethel, Connecticut to Norwalk 345 KV transmission project was completed and energized and it has operated reliably since then. In addition to improving reliability, we believe the completion of that project is the primary reason for the decrease in Connecticut congestion costs, which were lower by nearly $150 million in the project's first full year of operation.

Distribution and Generation Segment: A summary of distribution and generation segment capital expenditures by company in 2007, 2006 and 2005 is as follows (millions of dollars):

	For the Years Ended December 31,		
	2007	2006	2005
CL&P	**$283.3**	$210.3	$254.6
PSNH	**123.6**	109.6	143.6
WMECO	**34.0**	30.0	32.4
Yankee Gas	**63.7**	89.9	78.5
Other	**0.4**	2.3	1.0
Totals	**$505.0**	$442.1	$510.1

Capital expenditures at Yankee Gas above included $12 million spent on its LNG storage and production facility in Waterbury, Connecticut in 2007. The facility was placed in service in July of 2007 on budget with a final cost of approximately $108 million and was filled with LNG by the end of October of 2007 to serve customers in the 2007/2008 heating season. The capital cost of this facility has been included in Yankee Gas's rates since July 1, 2007.

Strategic Initiatives: We are evaluating certain development projects that would benefit our customers, such as new regulated generating facilities, investments in advanced metering infrastructure (AMI) systems to provide time-of-use rates to our customers, and transmission projects to better interconnect new renewable generation in northern New England and Canada with southern New England, as well as interconnections within New Hampshire. The estimated capital expenditures and projected rate base amounts discussed above do not include expenditures related to these initiatives.

Transmission Rate Matters and FERC Regulatory Issues

CL&P, PSNH and WMECO and most other New England utilities, generation owners and marketers are parties to a series of agreements that provide for coordinated planning and operation of the region's generation and transmission facilities and the market rules by which these parties participate in the wholesale markets and acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent from all market participants, has served as the Regional Transmission Organization for New England since February 1, 2005. ISO-NE works to ensure the reliability of the New England transmission system, administers the independent system operator tariff (ISO Tariff), subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines which portion of the costs of our major transmission facilities are regionalized throughout New England.

Transmission – Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of our wholesale transmission revenues are collected under the ISO-NE FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, which we administer, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that we recover all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates were in an underrecovery position of approximately $23 million, which will be recovered from LNS customers in mid-2008. We believe that these rates will provide us with timely recovery of transmission costs, including costs of our major transmission projects.

FERC ROE Decision: As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), we recorded an estimated regulatory liability for refunds of $25.6 million as of December 31, 2006. In 2007, we completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision and refunded approximately $23.9 million to regional, local and localized transmission customers. The $1.7 million positive pre-tax difference ($1 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in earnings in 2007.

Pursuant to this FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, we submitted a revised compliance filing with the other New England transmission owners, which outlined the regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC approved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

The transmission segment of our regulated companies refunded approximately $2.2 million of revenues and interest related to the July 26, 2007 order (approximately $1.4 million after-tax), while the distribution segment of our regulated companies received a net after-tax benefit of approximately $0.3 million as a result of these refunds. The refunds, net of tax benefits, totaling $1.1 million after-tax were recorded in 2007.

Legislative Matters

Environmental Legislation: The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by certain northeastern states, including Massachusetts, New Hampshire and Connecticut, to develop a regional program for stabilizing and reducing Carbon Dioxide (CO_2) emissions from fossil fuel-fired electric generators. This initiative proposed to stabilize CO_2 emissions at current levels and requires a 10 percent reduction by 2018 from the initial 2009 permitted levels. Each signatory state committed to propose for approval legislative and regulatory mechanisms to implement the program.

On December 28, 2007, the Connecticut Department of Environmental Protection (DEP) released draft RGGI regulations and conducted a public hearing on February 8, 2008. The DEP plans to have these rules finalized by May of 2008 and to participate in a proposed open regional auction of CO_2 allowances in June of 2008. The DEP has proposed an auction of 91 percent of allocated CO_2 allowances, with the remainder set aside for certain clean energy projects. The DEP has also proposed the first compliance period affecting facilities to begin on January 1, 2009. Although neither CL&P nor Yankee Gas currently have any facilities subject to the RGGI program, CL&P expects the cost of purchased energy supply to increase due to RGGI requirements. NU Enterprises has a purchase contract with a facility that expires in 2012. This facility will likely be required to purchase CO_2 allowances.

On August 10, 2007, the Massachusetts DEP and the Division of Energy Resources released draft RGGI regulations. Final regulations are expected in early 2008, and Massachusetts also plans to participate in the June 2008 regional auction. Although WMECO has no facilities that would be subject to this rule, it also expects the cost of purchased energy to increase.

PSNH is our only regulated company that currently owns generation assets that could be subject to the RGGI standards. In New Hampshire, draft legislation has been proposed during the 2008 session that is consistent with the RGGI initiative. However, at this time, because the draft legislation has not yet been finalized and because the cost of CO_2 allowances under RGGI cannot be identified with any certainty, we are unable to determine the actual cost and its impact on customer rates in New Hampshire.

Many states and environmental groups have challenged certain of the federal laws and regulations relating to air emissions as not being sufficiently strict. As a result, it is possible that state and federal regulations could be developed that will impose more stringent limitations on emissions than are currently in effect.

Connecticut:

2007 Legislation: On June 4, 2007, Connecticut Governor Rell signed into law the Energy Efficiency Act. Among other provisions, the Act:

- Required electric distribution companies to file an integrated resource plan with the Connecticut Energy Advisory Board (CEAB). CL&P and UI filed a joint plan on January 2, 2008. The CEAB has 120 days to approve or modify it before forwarding the plan to the DPUC;
- Provides incentives for customers to reduce consumption, particularly during peak load periods;
- Requires electric distribution companies, including CL&P, to file proposals with the DPUC to build cost-of-service peaking generation facilities. CL&P filed a qualification submission with the DPUC on February 1, 2008 and expects to file a detailed proposal on or about March 3, 2008;
- Requires the DPUC to allow CL&P and other Connecticut electric distribution companies to buy generation assets that are for sale in Connecticut if the purchase is in the public interest;
- Requires the DPUC to decouple electric and natural gas distribution revenues from sales volumes in future rate cases in an effort to align the interests of customers and the utilities in pursuit of conservation and energy efficiency;
- Requires CL&P and other Connecticut electric distribution companies to offer advanced metering to customers which will support time-based pricing; and
- Allows LDCs to enter into bilateral contracts as a mechanism to meet their standard service obligations.

Subsequent regulatory developments that resulted from the passage of the Energy Efficiency Act are described in "Regulatory Developments and Rate Matters," included in this Management's Discussion and Analysis.

In 2007, the DPUC approved $85 million for energy efficiency and renewable programs to restore, in effect, funding to previously authorized levels. The fund is allocated 80 percent to CL&P and 20 percent to UI, and will be used to prepay securitization obligations previously incurred by Connecticut. This will enable CL&P to increase its annual energy efficiency spending by approximately $20 million beginning in mid-2008. CL&P anticipates it will be allowed to earn incentives on these higher levels of spending.

New Hampshire:

2007 Legislation: On May 11, 2007, New Hampshire Governor Lynch signed a law establishing renewable portfolio standards for electricity sold in the state and requiring that, beginning in 2008, increasing percentages of the electricity sold to retail customers have direct ties to renewable energy sources, with the highest percentage of 23.8 percent reached by 2025. PSNH will be required to comply with these standards, and presently plans to meet them through the purchase of Renewable Energy Certificates or through Alternative Compliance Payments allowed under state law. PSNH expects that the additional costs incurred in meeting this new requirement will be recovered through their energy service (ES) rates.

Additionally, on July 17, 2007, Governor Lynch signed a law which:

- Directed the state Site Evaluation Committee to develop new rules for siting renewable facilities by October 1, 2007;
- Adds utility ownership of distributed renewable generation and demand-side management to the topics that the legislature's standing State Energy Policy Committee should examine; and
- Directs the NHPUC to encourage upgrades to the transmission system in northern New Hampshire.

An NHPUC report detailing the current transmission infrastructure in northern New Hampshire and steps needed to upgrade it to accommodate additional renewable generation was forwarded to the legislature on December 1, 2007. This report indicated that a $200 million investment in this infrastructure would be needed to develop 400 to 500 additional MW of renewable generation. We are currently evaluating this development opportunity for PSNH and have not yet identified any specific investments.

Regulatory Developments and Rate Matters

Regulated Companies' Transmission Revenues – Retail Rates: A significant portion of our transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, which recover these costs through rates charged to their retail customers. CL&P and WMECO each have a retail transmission cost tracking mechanism as part of their rates, and PSNH implemented a transmission cost adjustment mechanism (TCAM) that was effective on a retroactive basis beginning on July 1, 2006 as part of its February 26, 2007 rate case settlement agreement. These tracking mechanisms allow the companies to charge their retail customers for transmission charges on a timely basis.

Forward Capacity Market: On March 6, 2006, ISO-NE and a broad cross-section of critical stakeholders from around the region, including CL&P and PSNH, filed a comprehensive settlement agreement at the FERC proposing an auction-based forward capacity market (FCM) mechanism in place of the previously proposed locational installed capacity mechanism, an administratively determined electric generation capacity pricing mechanism. The settlement agreement provided for a fixed level of compensation to generators from December 1, 2006 through May 31, 2010 without regard to location in New England, and annual forward capacity auctions, beginning in 2008 for the 1-year period beginning on June 1, 2010, and annually thereafter. On June 16, 2006, the FERC approved the March of 2006 settlement agreement, and the payment of fixed compensation to generators began on December 1, 2006. The FERC denied rehearing of the decision on October 31, 2006. Several parties have challenged the FERC's approval of the settlement agreement, and that challenge is now pending in the Court of Appeals. CL&P, PSNH and WMECO are currently recovering related costs from their customers.

The first forward capacity auction concluded in early February of 2008 for the capacity year of June of 2010 through May of 2011. The bidding reached the establishment minimum of $4.50 per kilowatt-month with 2,047 MW of excess remaining capacity, which means the effective capacity price will be $4.25 per kilowatt-month compared to the previously established price of $4.10 for the capacity year preceding June of 2010. These costs are recoverable in all jurisdictions through the currently established rate structures.

Connecticut – CL&P:

Distribution Rates: On January 1, 2007, CL&P implemented a $7 million annualized increase in distribution rates, the fourth of four annual increases in distribution rates approved by the DPUC in December of 2003. On July 30, 2007, CL&P filed an application with the DPUC to raise distribution rates by approximately $189 million (later revised to $182 million) effective on January 1, 2008, and approximately $21.9 million effective in January of 2009. In its application, CL&P cited a weak actual Regulatory ROE, which has been significantly lower than its 9.85 percent authorized Regulatory ROE since the end of 2004, and requested an authorized Regulatory ROE of 11 percent. The application also cited the December 31, 2007 expiration of $30 million of refunds per year to customers for four years totaling $120 million from previous overrecoveries and the need to upgrade CL&P's aging distribution facilities. On January 28, 2008, the DPUC approved $77.8 million, or 11.7 percent, and $20.1 million, or 2.6 percent, in annualized increases over CL&P's current distribution rates, effective on February 1, 2008 and 2009, respectively, which also represent a 0.9 percent increase on a total rates basis over December of 2007 rates and a 0.4 percent increase on a total rates basis over February of 2008 rates, respectively. These increases are based on an authorized Regulatory ROE of 9.4 percent. In addition, the DPUC approved substantially all of CL&P's requested distribution segment capital program of $294 million for 2008 and $288 million for 2009.

As required by the Energy Efficiency Act, CL&P's rate case application included a proposal to implement distribution revenue decoupling from the volume of electricity sales. CL&P proposed using a revenue per customer tracking mechanism in its rate case filing. In lieu of this proposal, the DPUC authorized a rate design that includes greater fixed recovery of distribution revenue. As compared to previous tariffs, this authorization intends for CL&P to recover proportionately greater revenue through the fixed customer and demand charges and proportionately lesser revenue through the per KWH charges. The DPUC intends for this rate design to leave CL&P's distribution revenue recovery less susceptible to changes in KWH sales and KWH usage per customer.

Time-of-Use Rates: On March 30, 2007, CL&P filed a metering compliance plan with the DPUC that would meet the DPUC's objective of making time-of-use rates available to all CL&P customers. CL&P's filing discussed the technology, implementation options and costs comparing an open AMI system deployed on a geographic basis to a fixed automated metering reading network system deployed on a usage-based priority schedule. The plan provided for full deployment by 2010. On July 2, 2007, CL&P filed a revised AMI plan consistent with the requirements of the Energy Efficiency Act, which provided for a less aggressive implementation schedule.

On December 19, 2007, the DPUC issued a final decision on CL&P's compliance plan that authorizes a pilot program involving 10,000 AMI meters and a rate design pilot to test new time-of-use and real-time rates to determine customer acceptance and load response to various pricing structures. CL&P will file a plan to implement the pilot by March 15, 2008 and is required to submit a report on the technical capability of the meters, customer response to the pilot and other related results by December 1, 2009. The costs associated with the pilot are authorized to be recovered from customers, initially through CL&P's Federally Mandated Congestion Charges (FMCC).

Standard Service and Last Resort Service Rates: CL&P's residential and small commercial customers who do not choose competitive suppliers are served under Standard Service (SS) rates, and large commercial and industrial customers who do not choose competitive suppliers are served under Last Resort Service (LRS) rates. On January 1, 2007, CL&P's combined average SS and LRS rates increased approximately 10.4 percent and remained in effect until July 1, 2007. On July 1, 2007, CL&P's combined average SS and LRS rates decreased approximately 3.5 percent and remained in effect until January 1, 2008. On January 1, 2008, CL&P's combined average SS and LRS rates decreased approximately 1.1 percent. CL&P is fully recovering the costs of its SS and LRS services on a timely basis.

FMCC Filings: On August 2, 2007, CL&P filed with the DPUC its semi-annual reconciliation to document actual FMCC charges (including Energy Independence Act charges, as defined below), Generation Service Charge (GSC) revenue and expenses and Energy Adjustment Clause (EAC) charges for the period January 1, 2007 through June 30, 2007. For the first half of 2007, the filing identified overrecoveries totaling approximately $64 million related to these charges. On January 23, 2008, the DPUC issued a final decision covering this period that approved all costs as filed. On February 5, 2008, CL&P filed with the DPUC its semi-annual FMCC, GSC and EAC reconciliation for the period July 1, 2007 through December 31, 2007, which also contained the revenue and cost information from the January 1, 2007 through June 30, 2007 period. This filing identified overrecoveries totaling approximately $105 million for the full year 2007. Of this total, approximately $88 million was included in the annual CL&P rate change effective January 1, 2008 Therefore, there is a net remaining overrecovery of approximately $17 million to be given to our customers in the future.

CTA and SBC Reconciliation: On March 30, 2007, CL&P filed its 2006 CTA and System Benefits Charge (SBC) reconciliation, which compared CTA and SBC revenues to revenue requirements, with the DPUC. On December 27, 2007, the DPUC approved CL&P's request to collect SBC revenues at an annual level of $37.6 million, effective on January 1, 2008.

Energy Independence and Energy Efficiency Acts: In April of 2007, pursuant to Public Act 05-01, "An Act Concerning Energy Independence" (Energy Independence Act), CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. The agreement has been approved by the DPUC. CL&P's annual payments under this agreement will depend on the price and quantity of energy purchased and are currently estimated to be approximately $15 million beginning in 2010 escalating to $20 million in 2025. CL&P and UI have signed a sharing agreement, which has been filed with and approved by the DPUC, under which they will share the costs and benefits of this contract and other contracts under this program, with 80 percent to CL&P and 20 percent to UI. CL&P's portion of the costs and benefits of this contract will be paid by or returned to CL&P's customers.

On January 30, 2008, the DPUC approved contracts with seven additional renewable energy projects including biomass, landfill gas and fuel cell projects generating a total of 109 MW of renewable energy. CL&P's share of the future costs of such contracts will be paid by CL&P's customers. A third round of solicitations is expected to be conducted by the Connecticut Clean Energy Fund (CCEF) for an additional 26 MW of renewable energy generation to be selected by October 1, 2008.

Also pursuant to the Energy Independence Act, the DPUC conducted a request for proposal process and selected three generating projects to be built or modified that would be eligible to sign contracts for differences (CfDs) with CL&P and UI for a total of approximately 782 MW of capacity. The process also selected one new demand response project for 5 MW. The CfDs obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets. The contracts are for periods of up to 15 years and are subject to another similar sharing agreement between CL&P and UI. These contracts have been approved by the DPUC and signed by CL&P or UI, whichever is the primary obligor. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers. The costs to CL&P under these agreements will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. For further information, see Note 5, "Derivative Instruments," to the consolidated financial statements.

The Energy Efficiency Act requires Connecticut electric distribution companies to negotiate in good faith to potentially enter into cost-of-service based contracts for the energy associated with the three above-mentioned generation projects that were awarded CfDs by the DPUC, for terms equivalent to the term lengths of the associated CfDs. These energy contracts must be approved by the DPUC if it finds that they will stabilize the cost of electricity for Connecticut ratepayers. Depending on its terms, a long-term contract to purchase energy from a project that is also under a CfD could result in CL&P consolidating these projects into its financial statements. CL&P would seek to recover from customers any costs that result from consolidation of a project. As of this date, only one of the three CfD project developers has requested that CL&P enter into negotiations for a potential energy purchase agreement.

Customer Service Docket: On February 27, 2007, the DPUC issued a final decision in a docket examining the manner of operation and accuracy of CL&P's electric meters. While finding that the meters generally operated within industry standards, the DPUC imposed significant new testing, analytical and reporting requirements on CL&P. The DPUC also found that CL&P failed to be responsive to customer complaints by refusing meter tests or not allowing customers to speak with supervisors. The decision acknowledges recent corrective actions taken by CL&P but requires changes in numerous CL&P customer service practices. The decision also places substantial new tracking and reporting obligations on CL&P. The decision does not fine CL&P but holds that possibility open if CL&P fails to meet benchmarks to be established in this docket.

Connecticut – Yankee Gas:

Yankee Gas Rate Relief: On June 29, 2007, the DPUC approved a rate case settlement agreement between Yankee Gas, the OCC and the DPUC's Prosecutorial Division that resulted in an annualized increase of $22.1 million, or 4.2 percent, in Yankee Gas's base rates effective on July 1, 2007. The $22.1 million increase is net of expected pipeline and commodity cost savings primarily from the operation of Yankee Gas's 1.2 bcf LNG storage facility. The decision allows Yankee Gas to recover the costs related to this facility and higher cost-of-service and includes an authorized Regulatory ROE of 10.1 percent. Yankee Gas's new rates do not reflect the revenue decoupling required by the Energy Efficiency Act, since the rate case was filed before the legislation was passed.

New Hampshire:

Delivery Service Rate Case: On May 25, 2007, the NHPUC approved a distribution and transmission rate case settlement agreement between PSNH, the NHPUC staff and the OCA. The settlement agreement included, among other items, a transmission cost tracking mechanism, effective on July 1, 2006, to be reset annually, and an allowed distribution ROE of 9.67 percent. The settlement agreement allowed for a $37.7 million estimated annualized rate increase ($26.5 million for distribution and $11.2 million for transmission in base rates subject to tracking) beginning on July 1, 2007, along with the previous $24.5 million annualized temporary distribution rate increase that was effective on July 1, 2006. The $37.7 million includes a one-year revenue increase of approximately $9 million related to additional revenues to recoup the difference between the temporary and permanent rates for the period of July 1, 2006 through June 30, 2007. An additional delivery revenue increase of $3 million took effect on January 1, 2008 with a final estimated rate decrease of approximately $9 million scheduled for July 1, 2008. The settlement agreement enabled PSNH to fund a $10 million annual reliability enhancement program and more adequately fund its major storm cost reserve.

The pre-tax earnings impact of the approximately $9 million of additional revenues related to the July 1, 2006 through June 30, 2007 time period was or will be recognized as follows: approximately $4.5 million attributable to 2006 retail transmission expense was recognized in the second quarter of 2007; $3 million attributable to distribution costs from July 1, 2006 through June 30, 2007 will be recognized over the 12-month period beginning on July 1, 2007; and the remaining $1.5 million of revenue will be captured as part of the 2007 retail transmission tracker and will be offset by an equal amount of retail transmission expenses.

SCRC/ES Reconciliation and Rates: On May 1, 2007, PSNH filed its 2006 stranded cost recovery charge (SCRC)/ES reconciliation with the NHPUC. On November 5, 2007, PSNH, the NHPUC Staff, and the OCA filed a proposed settlement with the NHPUC. On December 7, 2007, the settlement, which did not have a material impact on our 2007 earnings, was approved by the NHPUC.

On September 7, 2007, PSNH filed a petition with the NHPUC requesting a change in its SCRC rate for the period January 1, 2008 through December 31, 2008. The NHPUC issued an order on December 17, 2007, approving its SCRC rate of $0.0072 per KWH for 2008.

On September 7, 2007, PSNH filed a petition with the NHPUC requesting a change in its default ES rate for the period January 1, 2008 through December 31, 2008. The NHPUC issued an order on December 28, 2007, approving an ES rate of $0.0882 per KWH for 2008. As part of its order approving the ES rate, the NHPUC approved an increase in the allowed return on generation assets from 9.62 percent to 9.81 percent effective on January 1, 2008.

TCAM Rates: On June 1, 2007, PSNH filed a petition with the NHPUC seeking to establish a TCAM rate consistent with the rate case settlement agreement that was approved by the NHPUC on May 25, 2007. The TCAM rate filing was amended on June 6, 2007 to reflect updates to wholesale transmission rates that were made available to PSNH after the initial June 1, 2007 filing. The NHPUC issued an order on June 29, 2007 approving a TCAM rate of $0.00752 per KWH for the period July 1, 2007 through June 30, 2008.

Massachusetts:

Rate Case Settlement: On December 14, 2006, the Massachusetts Department of Public Utilities (formerly the Department of Telecommunications) (DPU) approved a rate case settlement agreement that included distribution rate increases of $1 million beginning on January 1, 2007 and an additional $3 million increase beginning on January 1, 2008. On January 1, 2008, WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. The net impact of this rate adjustment is an average 6.2 percent increase in customers' total bills.

Contingent Matters:

The items summarized below contain contingencies that may have an impact on our net income, financial position or cash flows. See Note 8A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the consolidated financial statements for further information regarding these matters.

- Procurement Fee Rate Proceedings: CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. We have not recorded amounts related to the 2005 or 2006 procurement fee in earnings, although we estimate that if CL&P's methodology is upheld, CL&P would record after-tax amounts of $3.3 million for 2006 and $3.6 million for 2005 in 2008.

  We have recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. If the DPUC does not allow recovery of $5.8 million for procurement fees in its final decision, then CL&P would record a loss and establish an obligation to refund its customers. Hearings were held on December 10, 2007 and January 3, 2008. The new schedule calls for a draft decision in this docket to be issued on March 7, 2008.

- Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas's Purchased Gas Adjustment (PGA) clause charges and required an audit of approximately $11 million in previously recovered PGA revenues associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. The audit has concluded, and a final report has been submitted. A DPUC hearing was held on October 9, 2007. There is currently no final schedule in this case. We believe the unbilled sales and revenue adjustments and resulting charges to customers through the PGA clause for this period were appropriate and that the appropriateness of the PGA charges to customers for the time period under review will be approved.

- Transition Cost Reconciliations: WMECO filed its 2005 transition cost reconciliation with the DPU on March 31, 2006 and filed its 2006 transition cost reconciliation with the DPU on March 31, 2007. The DPU opened a proceeding for these filings and evidentiary hearings were held on August 29, 2007. The briefing process was completed during October of 2007. The timing of the decision in this docket is uncertain. Management does not expect the outcome of the DPU's review of these filings to have a material adverse impact on WMECO's net income, financial position or cash flows.

Deferred Contractual Obligations

We have significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including our electric utility companies. These companies recover these costs through state regulatory commission-approved retail rates. A summary of each of our subsidiary's ownership percentage in the Yankee Companies at December 31, 2007 is as follows:

	CYAPC	YAEC	MYAPC
CL&P	**34.5%**	**24.5%**	**12.0%**
PSNH	**5.0%**	**7.0%**	**5.0%**
WMECO	**9.5%**	**7.0%**	**3.0%**
Totals	**49.0%**	**38.5%**	**20.0%**

Our percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC: Under the terms of the settlement agreement between CYAPC, the DPUC, the OCC, and Maine regulators, the parties agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars). Annual collections began in January of 2007, and were reduced from the $93 million originally requested for years 2007 through 2010 to lower levels ranging from $37 million in 2007 rising to $46 million in 2015. The reduction to annual collections was achieved by extending the collection period by 5 years through 2015 by reflecting the proceeds from a settlement agreement with Bechtel Power Corporation, by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. We believe CL&P and WMECO will recover their shares of this obligation from their customers. PSNH has recovered its share of these costs from its customers.

YAEC: On July 31, 2006, the FERC approved a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service previously filed by YAEC. This settlement agreement did not materially affect the level of 2006 charges. Under the settlement agreement, YAEC agreed to reduce its November 2005 decommissioning cost increase from $85 million to $79 million. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual decontamination and decommissioning expenses and the decommissioning trust fund's actual investment earnings. We believe that our $24.9 million share of the increase in decommissioning costs will ultimately be recovered from the customers of CL&P and WMECO (approximately $19.4 million and $5.5 million for CL&P and WMECO, respectively). PSNH has recovered its share of these costs from its customers.

MYAPC: MYAPC is collecting revenues from CL&P, PSNH, WMECO and other owners that are adequate to recover the remaining cost of decommissioning its plant, and CL&P and WMECO expect to recover their respective shares of such costs through future rates. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed spent nuclear fuel pool operating expenses.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December of 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December of 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow.

CL&P, PSNH and WMECO's aggregate share of these damages is $44.7 million. Their respective shares of these damages are as follows: CL&P: $29 million; PSNH: $7.8 million; and WMECO: $7.9 million. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, we do believe that any net settlement proceeds we receive would be incorporated into FERC-approved recoveries, which would be passed on to our customers, through reduced charges.

NU Enterprises Divestitures

We have exited most of our competitive businesses. NU Enterprises continues to manage to completion its remaining wholesale marketing contracts and energy services activities.

Wholesale Marketing Business: During 2007, Select Energy continued to manage its remaining obligations in the PJM power pool and a long-term contract with the New York Municipal Power Agency (NYMPA), which will expire in 2013. Four of the five wholesale sales contracts that were remaining in the PJM pool at the beginning of 2007 expired on May 31, 2007. The remaining PJM wholesale sales contract will expire on May 31, 2008. The NYMPA and PJM contracts, as well as the related supply contracts, are derivatives that have been marked to market through earnings and have a negative fair value of $94 million as of December 31, 2007. In addition to the PJM and NYMPA contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase the output of a certain generating facility in New England through 2012. As a non-derivative contract, the fair value of the contract has not been reflected on the balance sheet, and the contract has not been marked to market. Based on the current estimated value of this non-derivative contract, when combined with the fair value of the derivative contracts at December 31, 2007, we believe, under present conditions, that the estimated total net cash cost at December 31, 2007 to exit the remaining wholesale contracts if served out or settled at the same time is approaching break-even.

Retail Marketing Business: On June 1, 2006, Select Energy sold its retail marketing business and paid $24.4 million in 2006 and $14.7 million in 2007 to the purchaser, completing our obligation.

Competitive Generation Business: We completed the sale of NU Enterprises' competitive generation assets on November 1, 2006.

Energy Services Businesses: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. In 2007, the energy services businesses recorded an after-tax gain of approximately $2.6 million related to the favorable resolution of certain legal and contract issues.

Also in 2007, the remaining contracts of SECI and former Woods Electrical were wound down. For further information regarding these companies, see Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements.

In connection with the sale of the retail marketing business, the competitive generation business and certain of the energy services businesses, we provided various guarantees and indemnifications to the purchasers of those businesses. See Note 8H, "Commitments and Contingencies – Guarantees and Indemnifications," to the consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: At December 31, 2007 and 2006, the fair values of NU Enterprises' (through its subsidiary Select Energy) wholesale derivative assets and derivative liabilities, which are subject to mark-to-market accounting, are as follows:

(Millions of Dollars)	December 31, 2007	2006
Current wholesale derivative assets	$ 36.2	$ 43.6
Long-term wholesale derivative assets	7.2	22.3
Current wholesale derivative liabilities	(64.9)	(82.3)
Long-term wholesale derivative liabilities	(72.5)	(110.1)
Portfolio position	$(94.0)	$(126.5)

Numerous factors could either positively or negatively affect the realization of the wholesale derivative net fair value amounts in cash. These factors include the amounts paid or received to exit some or all of these derivative contracts, the volatility of commodity prices until the derivative contracts are exited or expire, the outcome of future transactions, differences between expected and actual volumes, the performance of counterparties, and other factors.

Select Energy has policies and procedures requiring all of its wholesale derivative energy positions to be valued daily and segregating responsibilities between the individuals actually transacting (front office) and those confirming the trades (middle office). The middle office is responsible for determining the portfolio's fair value independent from the front office.

The methods Select Energy used to determine the fair value of its wholesale derivative contracts are identified and segregated in the table of fair value of wholesale derivative contracts at December 31, 2007 and 2006. A description of each method is as follows: 1) prices actively quoted primarily represent New York Mercantile Exchange futures and swaps that are marked to closing exchange prices; and 2) prices provided by external sources primarily include over-the-counter forwards and options, including bilateral contracts for the purchase or sale of electricity, and are marked to the mid-point of bid and ask market prices. The mid-points of market prices are adjusted to include all applicable market information, such as prior contract settlements with third parties. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based on a model. The model utilizes natural gas prices and a conversion factor to electricity for off-peak prices in 2012 and for all prices in 2013. Broker quotes for electricity at locations for which Select Energy has entered into transactions are generally available through the year 2011 for all prices and through 2012 for on-peak prices.

Generally, valuations of short-term derivative contracts derived from quotes or other external sources are more reliable should there be a need to liquidate the contracts, while valuations for longer-term derivative contracts are less certain. Accordingly, there is a risk that derivative contracts will not be realized at the amounts recorded.

At December 31, 2007 and 2006, the sources of the fair values of wholesale derivative contracts are included in the following tables:

(Millions of Dollars)	Fair Value of Wholesale Contracts at December 31, 2007			
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Maturity in Excess of Four Years	Total Fair Value
Prices actively quoted	$ (4.7)	$ (0.2)	$ 1.4	$ (3.5)
Prices provided by external sources	(24.0)	(38.8)	(13.4)	(76.2)
Model-based	—	4.3	(18.6)	(14.3)
Totals	$(28.7)	$(34.7)	$(30.6)	$(94.0)

(Millions of Dollars)	Fair Value of Wholesale Contracts at December 31, 2006			
Sources of Fair Value	Maturity Less than One Year	Maturity of One to Four Years	Maturity in Excess of Four Years	Total Fair Value
Prices actively quoted	$ (6.9)	$(11.2)	$ (1.9)	$ (20.0)
Prices provided by external sources	(32.2)	(44.8)	(12.7)	(89.7)
Model-based	0.4	3.5	(20.7)	(16.8)
Totals	$(38.7)	$(52.5)	$(35.3)	$(126.5)

For the years ended December 31, 2007 and 2006, the changes in fair value of these derivative contracts are included in the following table:

(Millions of Dollars)	Total Portfolio Fair Value Years Ended December 31, 2007	2006
Fair value of wholesale contracts outstanding at the beginning of the year	$(126.5)	$(230.1)
Contracts realized or otherwise settled during the year	38.9	118.9
Changes in fair value recorded:		
Fuel, purchased and net interchange power	(6.4)	(15.4)
Operating revenues	—	0.1
Fair value of wholesale contracts outstanding at the end of the year	$ (94.0)	$(126.5)

For further information regarding Select Energy's derivative contracts, see Note 5, "Derivative Instruments," to the consolidated financial statements.

Counterparty Credit: Counterparty credit risk relates to the risk of loss that Select Energy would incur because of non-performance by counterparties pursuant to the terms of their contractual obligations. Select Energy has established credit policies with regard to its counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances (including cash advances, LOCs, and parent guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. This evaluation results in Select Energy establishing credit limits prior to entering into contracts. The appropriateness of these limits is subject to our continuing review. Concentrations among these counterparties may affect Select Energy's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes to economic, regulatory or other conditions. At December 31, 2007, Select Energy's counterparty credit exposure to wholesale and trading counterparties of approximately one percent was collateralized, approximately 21 percent was rated BBB- or better and approximately 78 percent was non-rated. The composition of Select Energy's credit portfolio has shifted from being largely investment grade-rated to being mostly non-rated. This is largely due to the exit from the New

England wholesale and retail portfolios and the expiration of PJM obligations. The bulk of the non-rated credit exposure is comprised of one counterparty that is a creditworthy, non-rated public entity.

Off-Balance Sheet Arrangements

Regulated Companies: The CL&P Receivables Corporation (CRC) is a wholly-owned subsidiary of CL&P. CRC has an agreement with CL&P to purchase their accounts receivable and unbilled revenues and has an arrangement with a highly-rated financial institution under which CRC can sell up to $100 million of an undivided interest in accounts receivable and unbilled revenues. At December 31, 2007, there were $20 million of these sales. At December 31, 2006, CL&P had made no such sales.

CRC was established for the sole purpose of acquiring and selling CL&P's accounts receivable and unbilled revenues and is included in CL&P's and NU's consolidated financial statements. On July 3, 2007, CL&P extended the bank commitment under the Receivables Purchase and Sale Agreement with CRC and the financial institution through June 30, 2008 and extended the facility termination date to June 21, 2012. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under Statement of Financial Accounting Standards (SFAS) No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities - A Replacement of SFAS No. 125."

While a part of our cash management facilities, this off-balance sheet arrangement is not significant to our liquidity. There are no known events, demands, commitments, trends, or uncertainties that will, or are reasonably likely to, result in the termination or material reduction in the amount available to us under this off-balance sheet arrangement.

NU Enterprises: We have various guarantees and indemnification obligations outstanding on behalf of former subsidiaries in connection with the exit from the NU Enterprises businesses. See Note 8H, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding the maximum exposure and amounts recorded under these guarantees and indemnification obligations.

Enterprise Risk Management

We have implemented an Enterprise Risk Management (ERM) methodology for identifying the principal risks to the company. ERM involves the application of a well-defined, enterprise-wide methodology that will enable our Risk and Capital Committee, comprised of our senior officers, to oversee the identification, management and reporting of the principal risks of the business. However, there can be no assurances that the ERM process will identify every risk or event that could impact our financial condition or results of operations. The findings of this process are periodically discussed with our Board of Trustees.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates, assumptions and at times difficult, subjective or complex judgments. Changes in these estimates, assumptions and judgments, in and of themselves, could materially impact our financial statements. Our management communicates to and discusses with our Audit Committee of the Board of Trustees all critical accounting policies and estimates. The following are the accounting policies and estimates that we believe are the most critical in nature. See Note 1, "Summary of Significant Accounting Policies," to our consolidated financial statements for other accounting policies, estimates and assumptions used in the preparation of our consolidated financial statements.

Accounting for Environmental Reserves: Environmental reserves are accrued using probabilistic assessments when it is probable that a liability has been incurred and an amount can be reasonably estimated. Adjustments made to environmental reserves could have a significant effect on earnings. Our approach estimates the liability based on the most likely action plan from a variety of available remediation options, ranging from no action to remedies ranging from establishing institutional controls to full site remediation and long-term monitoring. Our approach estimates the liabilities associated with each possible action plan based on findings through various phases of site assessments.

These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations and several cost estimates from third-party engineering and remediation contractors. These amounts also take into consideration prior experience in remediating contaminated sites and data released by the United States Environmental Protection Agency and other organizations. These estimates are subjective in nature partly because there are usually several different remediation options from which to choose when working on a specific site. These estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations. The amounts recorded as environmental liabilities on the consolidated balance sheets represent our best estimate of the liability for environmental costs based on current site information from site assessments and remediation estimates. These liabilities are estimated on an undiscounted basis.

We remain in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits. HWP is at least partially responsible for this site, and substantial remediation activities at this site have already been conducted. These activities are the subject of ongoing discussions with the Massachusetts Department of Environmental Protection. The ultimate remediation requirements and costs will depend, among other things, on the level and extent of the remaining tar required to be removed, the extent of HWP's responsibility and the related scope and timing, all of which are difficult to estimate because of a number of uncertainties at this time. Therefore we cannot predict the outcome of this matter or its ultimate effect on us. HWP's share of the remediation costs related to this site is not recoverable from ratepayers. There were no changes to the environmental reserve for this site in 2007. Any additional increase to the environmental remediation reserve for this site would be recorded in earnings in future periods when it is reasonably estimable and probable, and potential increases may be material.

Income Taxes: Income tax expense is calculated in each reporting period in each of the jurisdictions in which we operate. This process involves estimating actual current tax expense or benefit as well as the income tax impact of temporary differences resulting from differing treatment of items, such as timing of the deduction and expenses for tax and book accounting purposes. These differences result in deferred tax assets and liabilities that are recorded on the consolidated balance sheets. Adjustments made to income tax estimates can significantly affect our consolidated financial statements. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in tax laws, our financial conditions in future periods and the final review of filed tax returns by taxing authorities. We must assess the likelihood that deferred tax assets will be recovered from future taxable income, and to the extent that recovery is not likely, a valuation allowance is established. Significant judgment is required in determining income tax expense, deferred tax assets and liabilities and valuation allowances.

We account for deferred taxes under SFAS No. 109, "Accounting for Income Taxes." We have established a regulatory asset for temporary differences recorded as deferred tax liabilities that will be recovered in rates in the future. The regulatory asset amounted to $335.5 million and $308 million at December 31, 2007 and 2006, respectively. Regulatory agencies in certain jurisdictions in which our regulated companies operate require the tax effect of specific temporary differences to be "flowed through" to utility customers. Flow through treatment means that deferred tax expense is not recorded on the consolidated statements of income/(loss). Instead, the tax effect of the temporary difference impacts both amounts for income tax expense currently included in customers' rates and the company's net income. Flow through treatment can result in effective income tax rates that are significantly different than expected income tax rates.

A reconciliation of expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in Note 1G, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial statements.

Effective on January 1, 2007, we implemented Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." FIN 48 applies to all income tax positions reflected on our balance sheets that have been included in previous tax returns or are expected to be included in future tax returns. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with tax positions that are deemed to be uncertain, including related interest and penalties. As a result of implementing FIN 48, we recognized a cumulative effect of a change in accounting principle of $41.8 million as a reduction to the January 1, 2007 balance of retained earnings.

The determination of whether a tax position meets the recognition threshold under FIN 48 is based on facts, circumstances and information available to us. Once a tax position meets the recognition threshold, the tax benefit is measured using a cumulative probability assessment. Assigning probabilities in measuring a recognized tax position and evaluating new information or events in subsequent periods could change previous conclusions used to measure the tax position estimate. This requires significant judgment. New information or events may include tax examinations or appeals, developments in case law, settlements of tax positions, changes in tax law and regulations, rulings by taxing authorities and statute of limitation expirations. Such information or events may have a significant impact on our net income, financial position and cash flows.

Derivative Accounting: Certain regulated companies' contracts for the purchase or sale of energy or energy related products are derivatives, along with all but one of Select Energy's remaining wholesale marketing contracts.

The application of derivative accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, is complex and requires our judgment in the following respects: election and designation of the normal purchases and sales exception, identification of derivatives and embedded derivatives, identifying hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on our consolidated earnings.

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the company determines whether it is a derivative using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts.

The judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. We currently have elected normal on many regulated company derivative contracts. If facts and circumstances change and we can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied.

In 2007, CL&P entered into CfDs with owners of plants to be built or modified. The CfDs are derivatives that are required to be marked to market on the balance sheet. However, due to the significance of the non-observable capacity prices associated with modeling the fair values of these contracts, their initial fair values were not recorded in CL&P's financial statements pursuant to EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." This guidance applies to initial fair values only, and not to subsequent changes in value. Subsequent changes in the values of these contracts were substantial, primarily due to reductions in the expected market prices of capacity. Accordingly, at December 31, 2007, we estimated and recorded on CL&P's balance sheet approximately $110 million of total negative changes in fair value of the derivative contracts since inception. The initial estimated negative fair values of these contracts of approximately $100 million will be recorded as part of the effect on derivatives of implementing FAS 157 in the first quarter of 2008. The $110 million net change in contract value was recorded as a regulatory asset as the costs of the contracts are recoverable from CL&P's customers. Significant judgment was involved in estimating the fair values of the contracts, including projections of capacity prices and reflecting the probabilities of cash flows considering the risks and uncertainties associated with the contracts.

Our regulated companies, particularly CL&P and PSNH, have entered into agreements which are derivatives and do not meet the normal purchases and sales exception. These contracts are marked to market and included in derivative assets and liabilities on the accompanying consolidated balance sheets. The offset to these derivatives are recorded as regulatory assets or liabilities as these amounts are recoverable from or refunded to our customers as they are incurred. The measurement of many of these contracts is extremely complex, as contracts are long-dated and many of the variables, such as discount rates, future energy and energy-related product prices, and the risk associated with projects that have not been completed, require significant management judgment.

For further information, see Note 1E, "Summary of Significant Accounting Policies - Derivative Accounting," and Note 5, "Derivative Instruments," to the consolidated financial statements.

Goodwill and Intangible Assets: SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill balances be reviewed for impairment at least annually by applying a fair value-based test. The testing of goodwill for impairment requires us to use estimates and judgment. We have selected October 1st of each year as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount of the goodwill. If goodwill is deemed to be impaired, it is written off to the extent it is impaired.

We completed our impairment analysis as of October 1, 2007 for the Yankee Gas goodwill balance of $287.6 million and determined that no impairment exists. In performing the required impairment evaluation we estimated the fair value of the Yankee Gas reporting unit and compared it to the carrying amount of the reporting unit, including goodwill. We estimated the fair value of Yankee Gas using discounted cash flow methodologies and an analysis of comparable companies or transactions. This analysis requires the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, and long-term earnings and merger multiples of comparable companies. We determined the discount rate using the capital asset pricing model methodology. This methodology uses a weighted average cost of capital in which the return on equity is calculated using risk-free rates, stock premiums and a beta representing specific market volatility. The component of the discount rate that changed the most from year to year is the beta, which increased in both 2006 and 2007. All of these assumptions are critical to the estimate and can change from period to period.

Updates to these assumptions in future periods, particularly changes in discount rates, could result in future impairments of goodwill. Although our recent evaluations have not resulted in impairment, the estimated fair value of Yankee Gas is highly sensitive to changes in assumptions. Holding all other assumptions constant, if the risk adjusted discount rate increased by 0.3 percent from approximately 7.2 percent to approximately 7.5 percent, then the estimated fair value of Yankee Gas would be equal to its carrying value.

Revenue Recognition: The determination of energy sales to individual customers is based on the reading of meters, which occurs on a systematic basis throughout the month. Billed revenues are based on these meter readings and the bulk of recorded revenues is based on actual billings. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and an estimated amount of unbilled revenues is also recorded.

Unbilled revenues represent an estimate of electricity or gas delivered to customers that has not yet been billed. Unbilled revenues are included in revenue on the statement of income/(loss) and are assets on the balance sheet that are reclassified to accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available, when changes in estimating methodology occur and under other circumstances. There were no changes in estimating methodology in 2007.

The regulated companies estimate unbilled revenues monthly using the daily load cycle (DLC) method. The DLC method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total calendar month sales to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective rate classes, then applying an average rate to the estimate of unbilled sales.

The estimate of unbilled revenues is sensitive to numerous factors, such as energy demands, weather and changes in the composition of customer classes that can significantly impact the amount of revenues recorded. Estimating the impact of these factors is complex and requires our judgment. The estimate of unbilled revenues is important to our consolidated financial statements, as adjustments to that estimate could significantly impact operating revenues and earnings.

For further information, see Note 1D, "Summary of Significant Accounting Policies - Revenues," to the consolidated financial statements and "Transmission Rate Matters and FERC Regulatory Issues" to this Management's Discussion and Analysis.

Regulatory Accounting: The accounting policies of the regulated companies conform to GAAP applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

During 2007, several items of a regulatory nature required our judgment. These items included:

- Procurement Fee: CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee, which was effective through 2006, and requested approval of the $5.8 million 2004 incentive fee. We have not recorded amounts related to the 2005 or 2006 procurement fee in earnings, though we estimate that if CL&P's methodology is upheld, CL&P would record after-tax amounts of $3.3 million for 2006 and $3.6 million for 2005 in 2008.

  We have recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. If the DPUC does not allow recovery of $5.8 million for procurement fees in its final decision, then CL&P would record a loss and establish an obligation to refund its customers.

For more information, see Note 8A, "Commitments and Contingencies – Regulatory Developments and Rate Matters," to the accompanying consolidated financial statements.

- Yankee Gas Unbilled Revenues: The DPUC is currently auditing a PGA adjustment related to two separate Yankee Gas's unbilled sales and revenue adjustments. The maximum amount under audit by the DPUC is $11 million. Based on the facts of the case, the supplemental information provided to the DPUC and the consultants' final report, we believe the appropriateness of the PGA charges to customers for the time period under review will be approved, and we have not reserved for any refund to customers. If the DPUC does not approve the calculation, we would record a decrease to earnings.

The application of SFAS No. 71 results in recording regulatory assets and liabilities. Regulatory assets represent the deferral of incurred costs that are probable of future recovery in customer rates. In some cases, we record regulatory assets before approval for recovery has been received from the applicable regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusion on certain factors, including but not limited to changes in the regulatory environment, recent rate orders issued by the applicable regulatory agencies and the status of any potential new legislation. Regulatory liabilities represent revenues received from customers to fund expected costs that have not yet been incurred or probable future refunds to customers.

We use our best judgment when recording regulatory assets and liabilities; however, regulatory commissions can reach different conclusions about the recovery of costs, and those conclusions could have a material impact on our consolidated financial statements. We believe it is probable that the regulated companies will recover the regulatory assets that have been recorded. If we determined that we could no longer apply SFAS No. 71 to our operations, or if we could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If we determine that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that we record the charge in earnings at that time.

For further information, see Note 1F, "Summary of Significant Accounting Policies – Regulatory Accounting," to the consolidated financial statements.

Pension and PBOP: Our subsidiaries participate in a uniform non-contributory defined benefit retirement plan (Pension Plan) covering substantially all our regular employees. In addition to the Pension Plan, we also participate in a postretirement benefits other than pensions (PBOP) Plan to provide certain health care benefits, primarily medical and dental, and life insurance benefits to retired employees. For each of these plans, the development of the benefit obligation, fair value of plan assets, funded status and net periodic benefit credit or cost is based on several significant assumptions. If these assumptions were changed, the resulting changes in benefit obligations, fair values of plan assets, funded status and net periodic expense could have a material impact on our consolidated financial statements.

Pre-tax periodic pension expense for the Pension Plan was $17.4 million, $52.7 million and $42.5 million for the years ended December 31, 2007, 2006 and 2005, respectively. The pension expense amounts exclude one-time items such as Pension Plan curtailments and termination benefits.

The pre-tax net PBOP Plan cost, excluding curtailments and termination benefits, was $38.4 million, $50.7 million and $49.8 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Long-Term Rate of Return Assumptions: In developing our expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, we evaluated input from actuaries and consultants, as well as long-term inflation assumptions and our historical 25-year compounded return of 11.8 percent. Our expected long-term rates of return on assets are based on certain target asset allocation assumptions. We believe that 8.75 percent is an appropriate aggregate long-term rate of return on Pension Plan and PBOP Plan assets (life assets and non-taxable health assets) and 6.85 percent for PBOP health assets, net of tax, for 2007. We will continue to evaluate these actuarial assumptions, including the expected rate of return, at least annually and will adjust the appropriate assumptions as necessary. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rates of return assumptions by asset category are as follows:

	At December 31,					
	Pension Benefits				Postretirement Benefits	
	2007		2006		2007 and 2006	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:						
United States	40%	9.25%	45%	9.25%	55%	9.25%
Non-United States	17%	9.25%	14%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	3%	10.25%	2%	10.25%
Private	8%	14.25%	8%	14.25%	—	—
Debt Securities:						
Fixed income	25%	5.50%	20%	5.50%	27%	5.50%
High yield fixed income	—	—	5%	7.50%	5%	7.50%
Real Estate	5%	7.50%	5%	7.50%	—	—

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. We routinely review the actual asset allocations and periodically rebalance the investments to the targeted asset allocations when appropriate. For information regarding actual asset allocations, see Note 6A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Pension and other post-retirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and post-retirement benefit payments. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility. As a result of these risks, it is reasonably probable that the market values of investment securities could increase or decrease in the near term, resulting in a material impact on the value of our pension assets. Increases or decreases in the market values could materially affect the current value of the trusts and the future level of pension and other-post retirement benefit expense. The current conditions in the credit market could negatively impact the assets in our trusts, but at this time we still believe that the 8.75 percent rate and the 6.85 percent rate for respective Pension and PBOP Plan assets are appropriate long-term rate of return assumptions.

Actuarial Determination of Expense: We base the actuarial determination of Pension Plan and PBOP Plan expense on a market-related value of assets (MRVA), which reduces year-to-year volatility. This MRVA calculation recognizes investment gains or losses over a four-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 MRVA and the actual return based on the fair value of assets. At December 31, 2007, total investment gains to be recognized in the MRVA over the next four years are $106.7 million and $1.5 million, for the Pension Plan and the PBOP Plan, respectively. As these asset gains are reflected in MRVA over the next four years, they will be subject to amortization with other unrecognized gains/losses. The Plans currently amortize unrecognized gains/losses as a component of pension and PBOP expense over 12 years, which is the average future service lives of the employees at December 31, 2007. At December 31, 2007, the net actuarial loss subject to amortization over the next 12 years was $65.2 million and $109.6 million, respectively, which excludes $106.7 million and $1.5 million of previous investment gains not currently reflected in the MRVA for the Pension Plan and PBOP Plan, respectively.

Discount Rate: The discount rate that is utilized in determining future pension and PBOP obligations is based on a yield-curve approach where each cash flow related to the Pension Plan or PBOP Plan liability stream is discounted at an interest rate specifically applicable to the timing of the cash flow. The yield curve is developed from the top quartile of AA rated Moody's and S&P's bonds without callable features outstanding at December 31, 2007. This process calculates the present values of these cash flows and calculates the equivalent single discount rate that produces the same present value for future cash flows. The discount rates determined on this basis are 6.6 percent for the Pension Plan and 6.35 percent for the PBOP Plan at December 31, 2007. Discount rates used at December 31, 2006 were 5.9 percent for the Pension Plan and 5.8 percent for the PBOP Plan.

Expected Contributions and Forecasted Expense: Due to the effect of the unrecognized actuarial (gains)/losses and based on the long-term rate of return assumptions and discount rates as noted above as well as various other assumptions, we estimate that expected contributions to and forecasted (income)/expense for the Pension Plan and PBOP Plan will be as follows (in millions):

	Pension Plan		Postretirement Plan	
Year	Expected Contributions	Forecasted Expense/ (Income)	Expected Contributions	Forecasted Expense
2008	$ —	$ 2.7	$36.2	$36.2
2009	$ —	$ 3.3	$33.7	$33.7
2010	$ —	$(8.0)	$31.3	$31.3

Future actual Pension and PBOP expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the plans and amounts capitalized. Beginning in 2007, we made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $3 million in 2007 and is estimated to be $4 million in 2008.

Sensitivity Analysis: The following represents the increase/(decrease) to the Pension Plan's and PBOP Plan's reported cost as a result of a change in the following assumptions by 50 basis points (in millions):

	At December 31,			
	Pension Plan Cost		Postretirement Plan Cost	
Assumption Change	**2007**	2006	**2007**	2006
Lower long-term rate of return	**$11.1**	$10.2	**$1.1**	$0.9
Lower discount rate	**$12.9**	$15.0	**$1.4**	$1.4
Lower compensation increase	**$ (6.9)**	$ (7.3)	**N/A**	N/A

Plan Assets: The market-related value of the Pension Plan assets has increased by $103.2 million to $2.5 billion at December 31, 2007. The Projected Benefit Obligation (PBO) for the Pension Plan decreased by $77.7 million to $2.3 billion at December 31, 2007. These changes have changed the funded status of the Pension Plan on a PBO basis from an overfunded position of $21.6 million at December 31, 2006 to an over-funded position of $202.5 million at December 31, 2007. The PBO includes expectations of future employee compensation increases. We have not made any employer contributions to the Pension Plan since 1991.

The accumulated benefit obligation (ABO) of the Pension Plan was approximately $454 million less than Pension Plan assets at December 31, 2007 and approximately $260 million less than Pension Plan assets at December 31, 2006. The ABO is the obligation for employee service and compensation provided through December 31, 2007.

The value of PBOP Plan assets has increased by $11.5 million to $278.1 million at December 31, 2007. The benefit obligation for the PBOP Plan has decreased by $10.3 million to $459.6 million at December 31, 2007. These changes have decreased the underfunded status of the PBOP Plan on an accumulated projected benefit obligation basis from $203.3 million at December 31, 2006 to $181.5 million at December 31, 2007. We have made a contribution each year equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits.

Health Care Cost: The health care cost trend assumption used to project increases in medical costs was 8.5 percent for 2008, decreasing one half percentage point per year to an ultimate rate of 5 percent in 2015. The effect of increasing the health care cost trend by one percentage point would have increased service and interest cost components of the PBOP Plan cost by $1 million in 2007 and $1.2 million in 2006. Changes in the long-term health care cost trend assumption could have a material impact on our financial statements.

Presentation: In accordance with GAAP, our consolidated financial statements include all subsidiaries over which control is maintained and would include any variable interest entities (VIE) for which we are the primary beneficiary. Determining whether we are the primary beneficiary of a VIE is complex, subjective and requires our judgment. There are certain variables taken into consideration to determine whether we are considered the primary beneficiary of a VIE. A change in any one of these variables could require us to reconsider whether or not we are the primary beneficiary of the VIE.

The Energy Independence Act requires the DPUC to investigate the financial impact on distribution companies of entering into long-term contracts for capacity or contracts to purchase renewable energy products from new generating plants. We reviewed each contract to determine the appropriate accounting treatment based on the terms of the contracts. Determining whether or not consolidation is required involves our judgment.

Pursuant to the Energy Independence Act, in April of 2007 CL&P entered into a 15-year agreement beginning in 2010 to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. We evaluated whether entering into the contract would require consolidation and determined that consolidation of the project would not be required. The review of this contract required significant management judgment.

In 2007, the DPUC approved two CL&P contracts associated with the capacity of two generating projects to be built or modified and two capacity-related contracts entered into by UI, one with a generating project to be built and one with a new demand response project. The contracts, referred to as CfDs, obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs with 80 percent to CL&P and 20 percent to UI. The ultimate cost to CL&P under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. We determined that these contracts do not require consolidation.

Changes in facts and circumstances resulting in reevaluation of the accounting treatment of these contracts could have a significant impact on the accompanying consolidated financial statements.

Other Matters

Consolidated Edison, Inc. Merger Litigation:

Certain gain and loss contingencies exist with regard to the merger agreement between us and Con Edison and the related litigation.

In 2001, Con Edison advised us that it was unwilling to close its merger with us on the terms set forth in the 1999 merger agreement (Merger Agreement). In March of 2001, we filed suit against Con Edison seeking damages in excess of $1 billion.

In a 2005 opinion, a panel of three judges at the Second Circuit held that our shareholders had no right to sue Con Edison for its alleged breach of our Merger Agreement. This ruling left intact the remaining claims between us and Con Edison for breach of contract, which includes our claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of at least $314 million. Any damage award would include pre-judgment interest from the date of the filing of the claim. Our request for a rehearing was denied in 2006. We opted not to seek review of this ruling by the United States Supreme Court. In April of 2006, we filed our motion for partial summary judgment on Con Edison's damage claim. On January 31, 2008, the trial judge denied a series of motions by both us and Con Edison that had been pending for more than one year, including our motion for an order dismissing Con Edison's synergy damage claim. The judge ordered the parties to be trial ready on four days' notice beginning March 21, 2008. It is not possible for us to predict either the outcome of this matter or its ultimate effect on us.

For further information regarding other commitments and contingencies, see Note 8, "Commitments and Contingencies," to the consolidated financial statements.

Accounting Standards Issued But Not Yet Adopted:

Fair Value Measurements: On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is applicable to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements.

SFAS No. 157 will be implemented prospectively with adjustments to fair values of derivatives in Select Energy's remaining portfolio reflected in earnings on January 1, 2008, similar to a change in estimate. These adjustments are expected to increase derivative liabilities due to the requirement to reflect the price that we would expect to pay a market participant to exit the contracts, partially offset by a reduction in derivative liabilities to reflect our nonperformance risk. We expect the pre-tax effect on earnings of implementing this new standard to be less than $10 million.

We are currently evaluating the effects of implementing SFAS No. 157 on our consolidated balance sheet. These effects will include adjustments to reflect the initial fair value of CL&P's derivative contracts that were in a gain or loss position at inception that was not recognized under previous accounting standards. SFAS No. 157 requires these adjustments to be recorded in retained earnings as of January 1, 2008. However, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers. Therefore, adjustments to reflect these previously unrecorded balances will be recorded as regulatory assets or liabilities. In addition, updates to the fair values of our regulated companies' previously recorded derivatives to reflect their exit prices and nonperformance risk will also be recorded as regulatory assets or liabilities.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. We are currently evaluating whether or not to elect the fair value option for our securities held in trust as of January 1, 2008. As of January 1, 2008, securities held in trust for the Supplemental Executive Retirement Plan (SERP) and non-SERP benefit plans had unrealized gains included in accumulated other comprehensive income of approximately $3 million after taxes that would be recorded as a cumulative-effect adjustment to retained earnings if SFAS No. 159 is implemented. Implementation of SFAS No. 159 for WMECO's securities held in its prior spent nuclear fuel trust is not expected to have a material effect on the financial statements.

Contractual Obligations and Commercial Commitments:

Information regarding our contractual obligations and commercial commitments at December 31, 2007 is summarized annually through 2012 and thereafter as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
Long-term debt maturities (a) (b)	$ 154.3	$ 99.3	$ 4.3	$ 4.3	$ 267.3	$2,814.8	$ 3,344.3
Estimated interest payments on existing debt (c)	190.7	186.3	182.1	181.7	171.2	2,185.3	3,097.3
Capital leases (d) (e)	3.5	3.6	1.8	1.9	2.0	17.4	30.2
Operating leases (e) (f)	30.5	27.5	24.1	19.1	14.5	47.3	163.0
Required funding of other postretirement benefit obligations (f)	36.2	33.7	31.3	29.9	28.4	N/A	159.5
Estimated future annual regulated company costs (e) (g)	1,131.4	520.3	539.4	726.7	681.8	2,187.6	5,787.2
Estimated future annual NU Enterprises costs (e) (g)	233.1	29.7	32.1	31.2	32.3	32.1	390.5
Other purchase commitments (f) (h)	1,116.7	—	—	—	—	—	1,116.7
Totals (i)	$2,896.4	$900.4	$815.1	$994.8	$1,197.5	$7,284.5	$14,088.7

(a) Included in our debt agreements are usual and customary positive, negative and financial covenants. Non-compliance with certain covenants, for example the timely payment of principal and interest, may constitute an event of default, which could cause an acceleration of principal payments in the absence of receipt by us of a waiver or amendment. Such acceleration would change the obligations outlined in the table of contractual obligations and commercial commitments.

(b) Long-term debt excludes $294.3 million of fees and interest due for spent nuclear fuel disposal costs, a positive $4.2 million of net changes in fair value and a negative $4.9 million of net unamortized premium and discount as of December 31, 2007.

(c) Estimated interest payments on fixed-rate debt are calculated by multiplying the coupon rate on the debt by its scheduled notional amount outstanding for the period of measurement. Estimated interest payments on floating-rate debt are calculated by multiplying the most recent floating-rate reset on the debt by its scheduled notional amount outstanding for the period of measurement. This same rate is then assumed for the remaining life of the debt. Interest payments on debt that have an interest rate swap in place are estimated using the effective cost of debt resulting from the swap rather than the underlying interest cost on the debt, subject to the fixed and floating methodologies.

(d) The capital lease obligations include imputed interest of $15.5 million as of December 31, 2007.

(e) We have no provisions in our capital or operating lease agreements or agreements related to the estimated future annual regulated company or NU Enterprises costs that could trigger a change in terms and conditions, such as acceleration of payment obligations.

(f) Amounts are not included on our consolidated balance sheets.

(g) Other than the net mark-to-market changes on respective derivative contracts held by both the regulated companies and NU Enterprises, these obligations are not included on our consolidated balance sheets. Estimated costs for 2008 are higher than costs in future years due to the timing of Select Energy purchase commitments and completion of transmission segment development projects. For further information on these estimated future annual costs, see Note 8D, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements.

(h) Amount represents open purchase orders, excluding those obligations that are included in the capital leases, operating leases, estimated future annual regulated company costs and the estimated future annual NU Enterprises costs. These payments are subject to change as certain purchase orders include estimates based on projected quantities of material and/or services that are provided on demand, the timing of which cannot be determined. Because payment timing cannot be determined, we include all open purchase order amounts in 2008.

(i) Excludes FIN 48 unrecognized tax benefits of $121.1 million as of December 31, 2007, as we cannot make reasonably reliable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

Rate reduction bond amounts are non-recourse to us or our subsidiaries have no required payments over the next five years and are not included in this table. The regulated companies' standard offer service contracts and default service contracts also are not included in this table. The estimated payments under interest rate swap agreements are not included in this table as the estimated payment amounts are not determinable. In addition, there are no Pension Plan contributions expected and therefore there are no amounts included in this table. For further information regarding our contractual obligations and commercial commitments, see the consolidated statements of capitalization and Note 4, "Short-Term Debt," Note 6A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 8D, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 11, "Leases," and Note 12, "Long-Term Debt," to the consolidated financial statements.

Forward Looking Statements: This discussion and analysis includes statements concerning our expectations, beliefs, plans, objectives, goals, strategies, assumptions of future events, financial performance or growth and other statements that are not historical facts. These statements are "forward looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can generally identify these "forward looking statements" through the use of words or phrases such as "estimate," "expect," "anticipate," "intend," "plan," "project," "believe," "forecast," "should," "could," and similar expressions. Forward looking statements involve risks and uncertainties that may cause actual results or outcomes to differ materially from those included in the forward looking statements. Factors that may cause actual results to differ materially from those included in the forward looking statements include, but are not limited to, actions by state and federal regulatory bodies, competition and industry restructuring, changes in economic conditions, changes in weather patterns, changes in laws, regulations or regulatory policy, changes in levels or timing of capital expenditures, developments in legal or public policy doctrines, technological developments, changes in accounting standards and financial reporting regulations, fluctuations in the value of our remaining competitive electricity positions, actions of rating agencies, and other presently unknown or unforeseen factors. Other risk factors are detailed from time to time in our reports to the Securities and Exchange Commission. We undertake no obligation to update the information contained in 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.

Web Site: Additional financial information is available through our web site at www.nu.com.

Results of Operations

The components of significant income statement variances for the past two years are provided in the table below (millions of dollars).

Income Statement Variances	2007 over/(under) 2006 Amount	Percent	2006 over/(under) 2005 Amount	Percent
Operating Revenues	**$(1,055)**	(15)%	$(469)	(6)%
Operating Expenses:				
Operation -				
Fuel, purchased and net interchange power	**(1,280)**	(28)	(898)	(16)
Other operation	**(152)**	(14)	109	11
Restructuring and impairment charges	**(8)**	(98)	(28)	(76)
Maintenance	**18**	9	16	9
Depreciation	**25**	10	16	7
Amortization	**24**	(a)	(187)	(92)
Amortization of rate reduction bonds	**13**	7	12	7
Taxes other than income taxes	**1**	1	3	1
Total operating expenses	**(1,359)**	(20)	(957)	(13)
Operating income/(loss)	**304**	(a)	488	(a)
Interest expense, net	**2**	1	—	—
Other income, net	**(3)**	(4)	10	18
Income/(loss) from continuing operations before income tax expense/(benefit)	**299**	(a)	498	(a)
Income tax expense/(benefit)	**186**	(a)	108	59
Preferred dividends of subsidiary	—	—	—	—
Income/(loss) from continuing operations	**113**	85	390	(a)
Income from discontinued operations	**(337)**	(100)	333	(a)
Cumulative effect of accounting change, net of tax benefit	—	—	1	100
Net income/(loss)	**$ (224)**	(48)%	$ 724	(a)%

(a) Percent greater than 100.

2007 Compared to 2006

Net income is $224 million lower in 2007 due to the two significant gains in 2006 which did not occur in 2007. These gains were an after-tax gain of $314 million associated with the sale of the competitive generation business and the CL&P $74 million income tax reduction associated with the PLR. The negative impact on net income of the 2006 gains was partially offset by the $107 million higher earnings of NU Enterprises due to the $96 million loss in 2006.

Operating Revenues

Operating revenues decreased $1.06 billion in 2007 primarily due to lower revenues from NU Enterprises ($794 million) and lower revenues from the regulated companies ($261 million). NU Enterprises' revenues decreased $794 million due to the exit from components of the competitive businesses during the latter part of 2006. The lower regulated revenues are being driven by the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms.

Revenues from the regulated companies decreased $261 million due to lower distribution segment revenues ($344 million), partially offset by higher transmission segment revenues ($83 million). Distribution segment revenues decreased $344 million primarily due to lower electric distribution revenues ($405 million), partially offset by higher gas distribution revenues ($61 million). Transmission segment revenues increased $83 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Lower electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($447 million). The distribution revenue tracking components decrease of $447 million is primarily due to the pass through of lower energy supply costs ($305 million), lower CL&P revenue associated with the recovery of delivery-related FMCC ($104 million), a decrease in PSNH's SCRC revenues mainly as a result of a rate decrease that went into effect July 1, 2006 ($76 million) and lower wholesale revenues ($28 million), partially offset by higher retail transmission revenues ($43 million), WMECO's higher transition cost recoveries ($15 million) and WMECO's pension and default service revenues ($8 million). The tracking mechanisms allow for rates to be changed periodically with over-collections refunded to customers or under-collections collected from customers in future periods.

The distribution component of electric distribution segment revenues which flows through to earnings increased $42 million primarily due to an increase in retail rates ($31 million) and retail sales ($11 million). Retail KWH electric sales increased by 1.5 percent in 2007 compared with 2006 (a 0.4 percent increase on a weather normalized basis). Firm gas sales increased 10.3 percent in 2007 compared with 2006 (a 3.1 percent increase on a weather normalized basis).

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $1.28 billion in 2007 due to lower expenses at NU Enterprises ($875 million) and lower costs at the regulated companies ($405 million). NU Enterprises' fuel expenses decreased due to the exit from significant components of the competitive businesses. Fuel expense from the regulated companies decreased primarily due to lower fuel, purchased and net interchange power expenses at CL&P, PSNH and WMECO ($431 million), mainly due to a decrease in standard offer supply costs as a result of a reduction in load caused by customer migration to third party suppliers, partially offset by higher Yankee Gas fuel expense ($26 million).

Other Operation

Other operation expenses decreased $152 million in 2007 primarily due to lower NU Enterprises expenses ($107 million) and lower regulated companies distribution and transmission segment expenses ($49 million).

NU Enterprises' expenses decreased $107 million primarily due to the exit from components of the competitive businesses during the latter part of 2006 and the $25 million donation to the NU Foundation in 2006

Lower regulated company distribution and transmission segment expenses of $49 million are primarily due to lower reliability must run (RMR) expenses at CL&P ($133 million), partially offset by higher Energy Independence Act (EIA) expenses which are tracked and recovered through the regulatory tracking mechanisms ($29 million), higher administration and general expenses at CL&P, WMECO and PSNH ($22 million), higher retail transmission expenses at PSNH and WMECO ($2[illegible] million) and Summer Savings Rewards Program which was implemented in 2007 at CL&P as a result of a legislative act ($14 million).

Restructuring and Impairment Charges

See Note 2, "Restructuring and Impairment Charges," to the consolidated financial statements for a description and explanation of these charges.

Maintenance

Maintenance expenses increased $18 million in 2007 primarily due to higher transmission segment expenses ($7 million) and regulated company distribution ($6 million).

Higher transmission segment expenses of $7 million in 2007 are primarily due to higher levels of employee support, compliance inspections, deferred maintenance, training, and unplanned repairs to transmission cables at CL&P.

Higher regulated company distribution expenses of $6 million in 2007 are primarily due to higher tree trimming ($3 million), equipment maintenance ($2 million) and underground line network inspection activities ($2 million).

Depreciation

Depreciation increased $25 million in 2007 primarily due to higher distribution and transmission depreciation expense as a result of higher plant balances from the ongoing construction program.

Amortization

Amortization increased $24 million in 2007 for the distribution segment primarily due to higher recovery of transition costs for CL&P ($32 million) and WMECO ($20 million) and the 2006 $18 million credit associated with the deferral of retail transmission costs for WMECO, partially offset by PSNH ($46 million). The PSNH decrease is primarily due to lower ES over recoveries, lower amortization levels of stranded costs, and the deferral of retail transmission costs.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $13 million in 2007. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of rate reduction bonds.

Interest Expense, Net

Interest expense increased $2 million in 2007 primarily due to higher interest for the regulated company distribution and transmission segments ($22 million), partially offset by lower interest at NU Enterprises ($19 million). The higher regulated company distribution and transmission segment interest is primarily due to long-term debt issuances for all four of the regulated companies. In 2007, $655 million of long-term debt was issued by the regulated companies consisting of $500 million for CL&P, $70 million for PSNH, $40 million for WMECO and $45 million for Yankee Gas.

Other Income, Net

Other income, net decreased $3 million, primarily due to a lower CL&P Traditional Standard Offer procurement fee ($11 million) and the absence of the gain on sale of investment in Globix Corporation (Globix) in 2006 ($3 million), partially offset by higher EIA incentives ($4 million), higher equity in earnings of regional nuclear generating and transmission companies ($4 million), and higher AFUDC equity ($4 million) mainly as a result of higher eligible construction work in progress.

Income Tax (Benefit)/Expense

Income tax expense increased $186 million primarily due to an increase in pre-tax earnings and lower favorable tax adjustments; partially offset by a decrease in flow through regulatory amortizations. In 2006, a significant portion of the tax adjustments included a $74 million tax benefit to remove deferred tax balances associated with the IRS PLR. Prior year flow through regulatory amortizations were higher as a result of the regulatory recovery of tax expense associated with nondeductible acquisition costs.

Income/(Loss) from Discontinued Operations

See Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements for a description and explanation of the discontinued operations.

2006 Compared to 2005

Operating Revenues

Operating revenues decreased $469 million in 2006 primarily due to lower revenues from NU Enterprises ($967 million), partially offset by higher revenues from the regulated companies for both the distribution segment ($450 million) and transmission segment ($48 million).

NU Enterprises' revenues decreased $967 million due to the exit from significant components of the competitive businesses during 2006.

Distribution revenues increased $450 million primarily due to higher electric distribution revenues ($500 million), partially offset by lower gas distribution revenues ($49 million). Higher electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues which are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($485 million). The distribution revenue tracking components increase of $485 million is primarily due to the pass through of higher energy supply costs ($566 million) and higher CL&P FMCC charges ($36 million), partially offset by lower PSNH SCRC revenues ($85 million) and lower wholesale revenues primarily due to the expiration or sale of CL&P market-based contracts ($41 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections collected from customers in future periods.

The distribution component of these electric distribution segments and the retail transmission component of PSNH which flow through to earnings increased $14 million primarily due to an increase in regulated retail rates, partially offset by a decrease in retail sales. The distribution retail electric sales were negatively affected by weather impacts in 2006 as compared with 2005 and by price elasticity driven by higher energy prices in 2006. Retail KWH electric sales decreased by 4.0 percent in 2006 compared with 2005 (a 1.6 percent decrease on a weather normalized basis). Absent the impacts of weather, management believes the decline in sales is primarily due to higher energy prices in 2006.

The increase in electric distribution revenues is partially offset by lower gas distribution revenues of $49 million primarily due to lower sales volumes. Firm gas sales decreased 11.2 percent in 2006 compared with 2005 primarily due to unseasonably warm weather in January, November and December of 2006 and customer reaction to higher energy prices. On a weather normalized basis, firm gas sales decreased 3.2 percent.

Transmission segment revenues increased $48 million primarily due to a higher transmission investment base and higher operating expenses which are recovered under FERC-approved transmission tariffs.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $898 million in 2006 primarily due to lower costs at NU Enterprises ($1.46 billion), partially offset by higher purchased power costs for the regulated companies distribution segment ($556 million).

NU Enterprises' lower costs of $1.46 billion are primarily due to the exit from significant components of the competitive businesses which includes lower mark-to-market expenses of $414 million.

The $556 million increase in distribution purchased power costs is primarily due to higher standard offer supply costs for CL&P and WMECO ($523 million) and higher expenses for PSNH primarily due to higher energy costs ($72 million). The increase in distribution purchased power costs is partially offset by lower Yankee Gas expenses as a result of lower gas sales ($39 million).

Other Operation

Other operation expenses increased $109 million in 2006 primarily due to higher regulated companies distribution and transmission segment expenses ($80 million) and higher NU Enterprises' expenses ($29 million).

Higher distribution and transmission expenses of $80 million are primarily due to higher expenses that are recovered in the distribution regulatory rate tracking mechanisms. These costs include higher distribution RMR costs and other power pool related expenses ($63 million) and higher CL&P conservation and load management expenses of $15 million. Distribution and transmission general and administrative expenses increased primarily due to higher employee related costs ($19 million), higher regulatory commission, outside service and other administrative costs ($6 million), partially offset by the absence of 2005 employee termination and benefit plan curtailment costs ($23 million) of which $21 million relates to regulated distribution that impact earnings.

NU Enterprises' expenses increased $29 million primarily due to a charge to record the retail marketing business at its fair value less cost to sell ($53 million) and a donation of $25 million to the NU Foundation, partially offset by lower expenses resulting from the exit from the competitive businesses ($49 million).

Restructuring and Impairment Charges

See Note 2, "Restructuring and Impairment Charges," to the consolidated financial statements for a description and explanation of these charges.

Maintenance

Maintenance expenses increased $16 million in 2006 primarily due to higher PSNH generation costs ($7 million) primarily as a result of a planned overhaul of a generating plant in 2006 and higher CL&P maintenance costs ($6 million) primarily due to storm-related tree trimming and overhead line maintenance expenses.

Depreciation

Depreciation increased $16 million in 2006 primarily due to higher distribution and transmission depreciation expense ($19 million) as a result of higher plant balances from the ongoing construction program. This increase is partially offset by lower NU Enterprises' depreciation ($4 million) from the competitive businesses not classified as discontinued operations.

Amortization

Amortization decreased $187 million in 2006 for the regulated companies distribution segment primarily due to PSNH distribution ($92 million), CL&P distribution ($71 million) and WMECO distribution ($24 million). The PSNH decrease is primarily due to completing the recovery of its non-securitized stranded costs as of June 30, 2006. The CL&P decrease is primarily due to lower amortization related to distribution's recovery of transition charges ($70 million). The WMECO decrease is primarily due to the deferral of transmission costs ($18 million), mainly as a result of higher RMR costs, and the deferral of transition costs ($5 million) as a result of lower transition revenues and higher transition costs.

Amortization of Rate Reduction Bonds

Amortization of rate reduction bonds increased $12 million in 2006. The higher portion of principal within the rate reduction bonds payment results in a corresponding increase in the amortization of regulatory assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $3 million in 2006 primarily due to higher distribution and transmission property taxes ($7 million) and higher Connecticut gross earnings tax ($3 million) primarily due to higher CL&P distribution revenues. These increases are partially offset by lower NU Enterprises' other taxes ($4 million) from the competitive businesses not classified as discontinued operations.

Other Income, Net

Other income, net increased $10 million in 2006 primarily due to a net decrease in non-competitive investment write-downs ($7 million), higher investment income ($6 million), CL&P EIA incentives ($5 million) and a $3 million gain associated with the sale of 2.7 million shares of Globix. These increases are partially offset by a lower CL&P procurement fee income ($7 million) and the CYAPC regulatory asset write-off ($3 million).

Income Tax (Benefit)/Expense

Included in the notes to the consolidated financial statements is a reconciliation of actual and expected tax expense. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions. In prior years, this rate-making treatment has required the company to provide the customers with a portion of the tax benefits associated with accelerated tax depreciation in the year it is generated (flow through depreciation). As these flow through differences turn around, higher tax expense is recorded.

Income tax benefit decreased $108 million in 2006 due to higher pre-tax earnings ($175 million) and the regulatory recovery of tax expense associated with nondeductible acquisition costs ($11 million); partially offset by favorable tax adjustments of $74 million to remove unamortized investment tax credits and EDIT deferred tax balances and $6 million related to generation plant sold to an affiliate.

Income from Discontinued Operations

NU's consolidated statements of income/(loss) for the years ended December 31, 2006 and 2005 present the operations for NGC, Mt. Tom, SESI, Former Woods Electrical – portion sold, Former Woods Electrical – remaining contracts, SECI-NH, SECI-CT and Woods Network as discontinued operations as a result of meeting the criteria requiring this presentation. Under this presentation, revenues and expenses of these businesses are included net of tax in income from discontinued operations on the consolidated statements of income/(loss) and all prior periods are reclassified. The 2006 income from discontinued operations includes the approximately $314 million gain on the sale of the competitive generation business. See Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements for a further description and explanation of the discontinued operations.

Cumulative Effect of Accounting Change, Net of Tax Benefit

A cumulative effect of accounting change, net of tax benefit ($1 million) was recorded in the fourth quarter of 2005 in connection with the adoption of FIN 47, which required NU to recognize a liability for the fair value of Asset Retirement Obligations.

COMPANY REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is responsible for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements of Northeast Utilities and subsidiaries (NU or the Company) and of other sections of this annual report. NU's internal controls over financial reporting were audited by Deloitte & Touche LLP.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting. The Company's internal control framework and processes have been 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. There are inherent limitations of internal controls over financial reporting that could allow material misstatements due to error or fraud to occur and not be prevented or detected on a timely basis by employees during the normal course of business. Additionally, internal controls over financial reporting may become inadequate in the future due to changes in the business environment.

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, NU conducted an evaluation of the effectiveness of internal controls over financial reporting based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation under the framework in COSO, management concluded that our internal controls over financial reporting were effective as of December 31, 2007.

February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Trustees and Shareholders of Northeast Utilities:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Northeast Utilities and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income/(loss), comprehensive income/(loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company's internal control over financial reporting as of December 31 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Company Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Northeast Utilities and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 1.G., the Company adopted Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109, as of January 1, 2007.

Deloitte & Touche LLP

Hartford, Connecticut
February 28, 2008

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	At December 31, 2007	2006
Assets		
Current Assets:		
Cash and cash equivalents	$ 15,104	$ 481,911
Special deposits	18,871	48,524
Investments in securitizable assets	308,182	375,655
Receivables, less provision for uncollectible accounts of $25,529 in 2007 and $22,369 in 2006	401,283	361,201
Unbilled revenues	101,860	88,170
Taxes receivable	13,850	—
Fuel, materials and supplies	210,850	173,882
Marketable securities - current	70,816	67,546
Derivative assets - current	105,517	88,699
Prepayments and other	39,923	45,305
Assets held for sale	—	158
	1,286,256	1,731,051
Property, Plant and Equipment:		
Electric utility	7,594,606	7,129,526
Gas utility	977,290	858,961
Other	310,535	299,389
	8,882,431	8,287,876
Less: Accumulated depreciation: $2,483,570 for electric and gas utility and $178,193 for other in 2007; $2,440,544 for electric and gas utility and $174,562 for other in 2006	2,661,763	2,615,106
	6,220,668	5,672,770
Construction work in progress	1,009,277	569,416
	7,229,945	6,242,186
Deferred Debits and Other Assets:		
Regulatory assets	2,057,083	2,449,132
Goodwill	287,591	287,591
Prepaid pension	202,512	21,647
Marketable securities - long-term	53,281	50,843
Derivative assets - long-term	298,001	271,755
Other	167,153	249,031
	3,065,621	3,329,999
Total Assets	$11,581,822	$11,303,236

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

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	At December 31, 2007	2006
Liabilities and Capitalization		
Current Liabilities:		
Notes payable to banks	$ 79,000	$ –
Long-term debt – current portion	154,286	4,877
Accounts payable	598,546	569,940
Accrued taxes	—	364,659
Accrued interest	56,592	53,782
Derivative liabilities – current	71,601	125,781
Other	246,125	244,734
Liabilities of assets held for sale	—	62
	1,206,150	1,363,835
Rate Reduction Bonds	917,436	1,177,158
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,067,490	1,099,433
Accumulated deferred investment tax credits	28,845	32,427
Deferred contractual obligations	222,908	271,528
Regulatory liabilities	851,780	809,324
Derivative liabilities – long-term	208,461	148,557
Accrued postretirement benefits	181,507	203,320
Other	383,611	322,840
	2,944,602	2,887,429
Capitalization:		
Long-Term Debt	3,483,599	2,960,435
Preferred Stock of Subsidiary – Non-Redeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value – authorized 225,000,000 shares; 175,924,694 shares issued and 155,079,770 shares outstanding in 2007 and 175,420,239 shares issued and 154,233,141 shares outstanding in 2006	879,623	877,101
Capital surplus, paid in	1,465,946	1,449,586
Deferred contribution plan – employee stock ownership plan	(26,352)	(34,766)
Retained earnings	946,792	862,660
Accumulated other comprehensive income	9,359	4,498
Treasury stock, 19,705,545 shares in 2007 and 19,684,249 shares in 2006	(361,533)	(360,900)
Common Shareholders' Equity	2,913,835	2,798,179
Total Capitalization	6,513,634	5,874,814
Commitments and Contingencies (Note 8)		
Total Liabilities and Capitalization	$11,581,822	$11,303,236

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

CONSOLIDATED STATEMENTS OF INCOME/(LOSS)

(Thousands of Dollars, except share information)	2007	For the Years Ended December 31, 2006	2005
Operating Revenues	$5,822,226	$6,877,687	$7,346,226
Operating Expenses:			
Operation –			
Fuel, purchased and net interchange power	3,350,673	4,630,798	5,528,600
Other	961,129	1,113,032	1,003,776
Restructuring and impairment charges	156	8,502	36,103
Maintenance	211,589	193,706	178,225
Depreciation	265,297	240,559	224,815
Amortization	40,674	16,292	202,949
Amortization of rate reduction bonds	201,039	188,247	176,356
Taxes other than income taxes	252,188	250,580	247,555
Total operating expenses	5,282,745	6,641,716	7,598,379
Operating Income/(Loss)	539,481	235,971	(252,153)
Interest Expense:			
Interest on long-term debt	162,841	141,579	131,870
Interest on rate reduction bonds	61,580	74,242	87,439
Other interest	15,824	22,375	19,276
Interest expense, net	240,245	238,196	238,585
Other Income, Net	61,639	64,394	54,532
Income/(Loss) from Continuing Operations Before Income Tax Expense/(Benefit)	360,875	62,169	(436,206)
Income Tax Expense/(Benefit)	109,420	(76,326)	(184,862)
Income/(Loss) from Continuing Operations Before Preferred Dividends of Subsidiary	251,455	138,495	(251,344)
Preferred Dividends of Subsidiary	5,559	5,559	5,559
Income/(Loss) from Continuing Operations	245,896	132,936	(256,903)
Discontinued Operations (Note 3):			
Income from Discontinued Operations	435	31,321	11,720
Gains/(Losses) from Sale/Disposition of Discontinued Operations	2,054	504,314	(1,123)
Income Tax Expense	1,902	197,993	6,177
Income from Discontinued Operations	587	337,642	4,420
Income/(Loss) Before Cumulative Effect of Accounting Change, Net of Tax Benefit	246,483	470,578	(252,483)
Cumulative Effect of Accounting Change, Net of Tax Benefit of $689	—	—	(1,005)
Net Income/(Loss)	$ 246,483	$ 470,578	$ (253,488)
Basic Earnings/(Loss) Per Common Share:			
Income/(Loss) from Continuing Operations	$ 1.59	$ 0.86	$ (1.95)
Income from Discontinued Operations	—	2.20	0.03
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	—	(0.01)
Basic Earnings/(Loss) Per Common Share	$ 1.59	$ 3.06	$ (1.93)
Fully Diluted Earnings/(Loss) Per Common Share:			
Income/(Loss) from Continuing Operations	$ 1.59	$ 0.86	$ (1.95)
Income from Discontinued Operations	—	2.19	0.03
Cumulative Effect of Accounting Change, Net of Tax Benefit	—	—	(0.01)
Fully Diluted Earnings/(Loss) Per Common Share	$ 1.59	$ 3.05	$ (1.93)
Basic Common Shares Outstanding (weighted average)	154,759,727	153,767,527	131,638,953
Fully Diluted Common Shares Outstanding (weighted average)	155,304,361	154,146,669	131,638,953

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS)

(Thousands of Dollars)	2007	For the Years Ended December 31, 2006	2005
Net Income/(Loss)	$ 246,483	$ 470,578	$ (253,488)
Other comprehensive income/(loss), net of tax:			
Qualified cash flow hedging instruments	(3,591)	(12,340)	21,688
Unrealized (losses)/gains on securities	(101)	718	(899)
Change in funded status of pension, SERP and other post retirement plans	8,553	—	—
Minimum SERP liability	—	379	418
Other comprehensive income/(loss), net of tax	4,861	(11,243)	21,207
Comprehensive Income/(Loss)	$ 251,344	$ 459,335	$ (232,281)

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Thousands of Dollars, except share information)	Common Shares Shares	Common Shares Amount	Capital Surplus, Paid In	Deferred Contribution Plan - ESOP	Retained Earnings	Accumulated Other Comprehensive (Loss)/Income	Treasury Stock	Total
Balance as of January 1, 2005	129,034,442	$ 756,155	$1,116,106	$ (60,547)	$ 845,343	$ (1,220)	$ (359,126)	$ 2,296,711
Net loss for 2005					(253,488)			(253,488)
Dividends on common shares - $0.675 per share					(87,554)			(87,554)
Issuance of common shares, $5 par value	23,666,723	118,334	332,493					450,827
Allocation of benefits - ESOP	590,173		(2,161)	13,663				11,502
Change in restricted shares, net	(65,446)		5,295				(1,084)	4,211
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			368					368
Capital stock expenses, net			(14,540)					(14,540)
Other comprehensive income						21,207		21,207
Balance as of December 31, 2005	153,225,892	874,489	1,437,561	(46,884)	504,301	19,987	(360,210)	2,429,244
Net income for 2006					470,578			470,578
Dividends on common shares - $0.725 per share					(112,219)			(112,219)
Issuance of common shares, $5 par value	522,535	2,612	6,882					9,494
Allocation of benefits - ESOP	523,452		(618)	12,118				11,500
Change in restricted shares, net	(38,738)		4,293				(690)	3,603
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			1,112					1,112
Capital stock expenses, net			356					356
Adjustment to funded status of pension, SERP and other post retirement plans (SFAS No. 158)						(4,246)		(4,246)
Other comprehensive loss						(11,243)		(11,243)
Balance as of December 31, 2006	154,233,141	877,101	1,449,586	(34,766)	862,660	4,498	(360,900)	2,798,179
Adoption of FIN 48 - accounting for uncertainty of income taxes					(41,816)			(41,816)
Net income for 2007					246,483			246,483
Dividends on common shares - $0.775 per share					(120,535)			(120,535)
Issuance of common shares, $5 par value	504,455	2,522	6,534					9,056
Allocation of benefits - ESOP	363,470		2,129	8,414				10,543
Change in restricted shares, net	(21,104)		4,368				(627)	3,741
Change in treasury stock	(192)		6				(6)	—
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			3,183					3,183
Capital stock expenses, net			140					140
Other comprehensive income						4,861		4,861
Balance as of December 31, 2007	**155,079,770**	**$879,623**	**$1,465,946**	**$(26,352)**	**$946,792**	**$ 9,359**	**$(361,533)**	**$2,913,835**

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	2007	For the Years Ended December 31, 2006	2005
Operating Activities:			
Net income/(loss)	$246,483	$470,578	$(253,488)
Adjustments to reconcile to net cash flows provided by operating activities:			
Pre-tax (gains)/losses from sale/disposition of discontinued operations	(2,054)	(504,314)	1,123
Restructuring and impairment charges	(2,304)	(2,282)	67,181
Bad debt expense	29,140	29,366	27,528
Depreciation	265,297	243,822	237,463
Deferred income taxes	6,933	(204,212)	(202,789)
Amortization	40,674	16,292	202,949
Amortization of rate reduction bonds	201,039	188,247	176,356
Amortization of recoverable energy costs	11,715	15,609	39,914
Pension expense, net of capitalized portion	18,143	38,677	42,662
Wholesale contract buyout payments	—	—	(186,531)
Regulatory overrecoveries/(refunds)	37,010	(96,560)	(65,236)
Derivative assets and liabilities	(43,808)	(98,685)	443,351
Deferred contractual obligations	(41,950)	(90,671)	(89,464)
Other non-cash adjustments	(6,766)	22,675	45,112
Other sources of cash	—	10,655	5,528
Other uses of cash	(21,088)	(10,134)	—
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(65,381)	605,366	(208,519)
Fuel, materials and supplies	(33,727)	16,718	(17,848)
Investments in securitizable assets	33,531	(158,651)	(113,410)
Other current assets	3,878	58,350	46,462
Accounts payable	(49,554)	(399,386)	131,043
Counterparty deposits and margin special deposits	29,505	26,469	(86,229)
Taxes (receivable)/accrued	(392,611)	271,477	156,630
Other current liabilities	(15,670)	(42,332)	41,416
Net cash flows provided by operating activities	248,435	407,074	441,204
Investing Activities:			
Investments in property and plant	(1,114,824)	(872,181)	(775,355)
Net proceeds from sales of competitive businesses	—	1,053,099	31,456
Cash payments related to the sale of competitive businesses	(16,648)	(32,359)	—
Proceeds from sales of investment securities	254,832	193,459	137,099
Purchases of investment securities	(261,777)	(193,917)	(142,260)
Rate reduction bond escrow and other deposits	63,722	(50,686)	45,955
Other investing activities	7,229	19,649	3,560
Net cash flows (used in)/provided by investing activities	(1,067,466)	117,064	(699,545)
Financing Activities:			
Issuance of common shares	9,056	9,494	450,827
Issuance of long-term debt	655,000	250,000	350,355
Retirements of rate reduction bonds	(259,722)	(173,344)	(195,988)
Increase/(decrease) in short-term debt	79,000	(32,000)	(148,000)
Retirements of long-term debt	(4,877)	(28,843)	(98,056)
Cash dividends on common shares	(120,988)	(112,745)	(87,554)
Other financing activities	(5,245)	(571)	(14,450)
Net cash flows provided by/(used in) financing activities	352,224	(88,009)	257,134
Net (decrease)/increase in cash and cash equivalents	(466,807)	436,129	(1,207)
Cash and cash equivalents - beginning of year	481,911	45,782	46,989
Cash and cash equivalents - end of year	$ 15,104	$481,911	$ 45,782

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars)		At December 31, 2007	2006
Common Shareholders' Equity		**$2,913,835**	$2,798,179
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption - $50 par value - authorized 9,000,000 shares in 2007 and 2006; 2,324,000 shares outstanding in 2007 and 2006; Dividend rates of $1.90 to $3.28; Current redemption prices of $50.50 to $54.00		**116,200**	116,200
Long-Term Debt:			
First Mortgage Bonds:			
Final Maturity	Interest Rates		
2009-2012	6.20% to 7.19%	**71,429**	75,714
2014-2017	4.80% to 6.15%	**695,000**	375,000
2019-2024	5.26% to 8.48%	**209,845**	209,845
2026-2037	5.35% to 8.81%	**830,000**	580,000
Total First Mortgage Bonds		**1,806,274**	1,240,559
Other Long-Term Debt:			
Pollution Control Notes:			
2016-2018	5.90%	**25,400**	25,400
2021-2022	Variable Rate and 4.75% to 6.00%	**428,285**	428,285
2028	5.85% to 5.95%	**369,300**	369,300
2031	3.35% until 2008	**62,000**	62,000
Other:			
2007-2009	Variable Rate and 3.30% to 8.81%	**195,000**	150,591
2012-2015	5.00% to 9.24%	**368,000**	368,000
2034-2037	5.90% to 6.70%	**90,000**	50,000
Total Pollution Control Notes and Other		**1,537,985**	1,453,576
Total First Mortgage Bonds, Pollution Control Notes and Other		**3,344,259**	2,694,135
Fees and interest due for spent nuclear fuel disposal costs		**294,305**	280,820
Change in fair value		**4,172**	(6,483)
Unamortized premium and discount, net		**(4,851)**	(3,160)
Total Long-Term Debt		**3,637,885**	2,965,312
Less: Amounts due within one year		**154,286**	4,877
Long-Term Debt, Net		**3,483,599**	2,960,435
Total Capitalization		**$6,513,634**	$5,874,814

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

A. About Northeast Utilities

Consolidated: Northeast Utilities (NU or the company) is the parent company of the regulated companies and NU Enterprises as defined below. Until February 8, 2006, NU was registered with the Securities and Exchange Commission (SEC) as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). On February 8, 2006, PUHCA was repealed. NU is now registered with the Federal Energy Regulatory Commission (FERC) as a public utility holding company under the PUHCA of 2005. Arrangements among the regulated companies, NU Enterprises and other NU companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. The regulated companies are subject to further regulation for rates, accounting and other matters by the FERC and/or applicable state regulatory commissions.

Regulated Companies: The regulated companies furnish franchised retail electric service in Connecticut, New Hampshire and Massachusetts through three companies: The Connecticut Light and Power Company (CL&P), Public Service Company of New Hampshire (PSNH) and Western Massachusetts Electric Company (WMECO). Another regulated company, Yankee Gas Services Company (Yankee Gas), owns and operates Connecticut's largest natural gas distribution system. The regulated companies include three reportable business segments: the electric distribution segment (which includes PSNH's generation activities), the gas distribution segment and the electric transmission segment.

NU Enterprises: NU Enterprises, Inc. is the parent company of Select Energy, Inc. (Select Energy), the E. S. Boulos Company (Boulos), Northeast Generation Services Company (NGS) and Select Energy Contracting, Inc. (SECI), which are collectively referred to as NU Enterprises. For information regarding NU's exit from these businesses, see Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements.

Several wholly-owned subsidiaries of NU provide support services for NU's companies. Northeast Utilities Service Company (NUSCO) provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to NU's companies. Three other subsidiaries construct, acquire or lease some of the property and facilities used by NU's companies.

In 2007 and 2006, NU and its subsidiaries made aggregate discretionary contributions of $3 million and $25 million, respectively, to the NU Foundation, Inc. (Foundation), an independent not-for-profit charitable entity designed to invest in projects that emphasize economic development, workforce training and education, and a clean and healthy environment. The board of directors of the Foundation consists of certain NU officers. The Foundation is not included in the consolidated financial statements of NU because the Foundation is a not-for-profit entity and because the company does not have title to the Foundation's assets and cannot receive contributions back from the Foundation. Any donations made to the Foundation negatively impact NU's earnings.

B. Presentation

The consolidated financial statements of NU and its subsidiaries, as applicable, include the accounts of all their respective subsidiaries. Intercompany transactions have been eliminated in consolidation.

The preparation of consolidated financial statements in conformity with accounting principles generally accepted 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 liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain reclassifications of prior period data included in the accompanying consolidated financial statements have been made to conform with the current year's presentation.

NU's consolidated statements of income/(loss) for the years ended December 31, 2007, 2006 and 2005 classify the following as discontinued operations:

- Northeast Generation Company (NGC), including certain components of NGS,
- The Mt. Tom generating plant (Mt. Tom) previously owned by Holyoke Water Power Company (HWP),
- Select Energy Services, Inc. (SESI) and its wholly-owned subsidiaries HEC/Tobyhanna Energy Project, Inc. and HEC/CJTS Energy Center LLC,
- A portion of the former Woods Electrical Co., Inc. (Woods Electrical),
- SECI (including Reeds Ferry Supply Co., Inc.), and
- Woods Network Services, Inc. (Woods Network).

Portions of SECI that were included in continuing operations in prior years have been reclassified to discontinued operations in the consolidated statements of income/(loss) for 2006 and 2005 as a result of the winding down of SECI operations in 2007. The amounts of these reclassifications are as follows:

(Millions of Dollars)	For the Years Ended December 31, 2006	2005
Operating revenue	$6.7	$51.5
Loss before income taxes	(13.5)	(12.6)
Gain from sale of discontinued operations	1.6	—
Income tax benefit	(5.1)	(2.9)
Net loss	(6.8)	(9.7)

For further information regarding discontinued operations, see Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements.

C. Accounting Standards Issued But Not Yet Adopted

Fair Value Measurements: On September 15, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value and is required to be implemented in the first quarter of 2008. The statement defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. SFAS No. 157 provides a fair value hierarchy, giving the highest priority to quoted prices in active markets, and is applicable to fair value measurements of derivative contracts that are subject to mark-to-market accounting and to other assets and liabilities that are reported at fair value or subject to fair value measurements.

SFAS No. 157 will be implemented prospectively with adjustments to fair values of derivatives in Select Energy's remaining portfolio reflected in earnings on January 1, 2008, similar to a change in estimate. These adjustments are expected to increase derivative liabilities due to the requirement to reflect the price that NU would expect to pay a market participant to exit the contracts, partially offset by a reduction in derivative liabilities to reflect the company's nonperformance risk. Management expects the pre-tax effect on earnings of implementing this new standard to be less than $10 million.

Management is currently evaluating the effects of implementing SFAS No. 157 on the consolidated balance sheet. These effects will include adjustments to reflect the initial fair value of CL&P's derivative contracts that were in a gain or loss position at inception that was not recognized under previous accounting standards. SFAS No. 157 requires these adjustments to be recorded in retained earnings as of January 1, 2008. However, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers. Therefore, adjustments to reflect these previously unrecorded balances will be recorded as regulatory assets or liabilities. In addition, updates to the fair values of the NU regulated companies' previously recorded derivatives to reflect their exit prices and nonperformance risk will also be recorded as regulatory assets or liabilities.

The Fair Value Option: On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - including an amendment of FAS 115." SFAS No. 159 allows entities to choose, at specified election dates, to measure at fair value eligible financial assets and liabilities that are not otherwise required to be measured at fair value. SFAS No. 159 is effective in the first quarter of 2008, with the effect of application to eligible items as of January 1, 2008 required to be reflected as a cumulative-effect adjustment to the opening balance of retained earnings. If a company elects the fair value option for an eligible item, changes in that item's fair value at subsequent reporting dates must be recognized in earnings. Management is currently evaluating whether or not to elect the fair value option for NU's securities held in trust as of January 1, 2008. As of January 1, 2008, securities held in trust for the Supplemental Executive Retirement Plan (SERP) and non-SERP benefit plans had unrealized gains included in accumulated other comprehensive income of approximately $3 million after taxes that would be recorded as a cumulative-effect adjustment to retained earnings if SFAS No. 159 is implemented. Implementation of SFAS No. 159 for WMECO's securities held in its prior spent nuclear fuel trust is not expected to have a material effect on the consolidated financial statements.

D. Revenues

Regulated Companies: The regulated companies' retail revenues are based on rates approved by the state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. However, certain regulated companies utilize regulatory commission-approved tracking mechanisms to track the recovery of certain incurred costs. The tracking mechanisms allow for rates to be changed periodically, with overcollections refunded to customers or undercollections collected from customers in future periods.

Regulated Companies' Unbilled Revenues: Unbilled revenues represent an estimate of electricity or gas delivered to customers for which customers have not yet been billed. Unbilled revenues are included in revenue on the statement of income/(loss) and are assets on the balance sheet that are reclassified to accounts receivable in the following month as customers are billed. Such estimates are subject to adjustment when actual meter readings become available or under other circumstances.

The regulated companies estimate unbilled revenues monthly using the daily load cycle (DLC) method. The DLC method allocates billed sales to the current calendar month based on the daily load for each billing cycle. The billed sales are subtracted from total calendar month sales to estimate unbilled sales. Unbilled revenues are estimated by first allocating sales to the respective rate classes, then applying an average rate to the estimate of unbilled sales.

Regulated Companies' Transmission Revenues - Wholesale Rates: Wholesale transmission revenues are based on formula rates that are approved by the FERC. Most of NU's wholesale transmission revenues are collected under the New England Independent System Operator (ISO-NE) FERC Electric Tariff No. 3, Transmission, Markets and Services Tariff (Tariff No. 3). Tariff No. 3 includes Regional Network Service (RNS) and Local Network Service (LNS) rate schedules to recover transmission and other services. The RNS rate, administered by ISO-NE and billed to all New England transmission users, is reset on June 1st of each year and recovers the revenue requirements associated with transmission facilities that benefit the New England region. The LNS rate, administered by NU, is reset on January 1st and June 1st of each year and recovers the revenue requirements for local transmission facilities and other transmission costs not recovered under the RNS rate, including 50 percent of the CWIP that is included in rate base on the remaining three southwest Connecticut projects (Middletown-Norwalk, Glenbrook Cables and Long Island Replacement Cable). The LNS rate calculation recovers total transmission revenue requirements net of revenues received from other sources (i.e., RNS, rentals, etc.), thereby ensuring that NU recovers all regional and local revenue requirements as prescribed in Tariff No. 3. Both the RNS and LNS rates provide for annual true-ups to actual costs. The financial impacts of differences between actual and projected costs are deferred for future recovery from or refund to retail customers. At December 31, 2007, the LNS rates were in an underrecovery position of approximately $23 million, which will be recovered from LNS customers in mid-2008. NU believes that these rates will provide it with timely recovery of transmission costs, including costs of its major transmission projects.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, which recover these costs through rates charged to their retail customers. CL&P and WMECO each have a retail transmission cost tracking mechanism as part of their rates, and PSNH implemented a transmission cost adjustment mechanism that was effective on a retroactive basis beginning on July 1, 2006 as part of its February 26, 2007 rate case settlement agreement. These tracking mechanisms allow the companies to charge their retail customers for transmission charges on a timely basis.

NU Enterprises: NU Enterprises' revenues are recognized at different times for its different business lines. Service revenues are recognized as services are provided, often on a percentage of completion basis. Up to and including the first quarter of 2005, wholesale marketing revenues were recognized when energy was delivered. Subsequent to March 31, 2005, as a result of applying mark-to-market accounting, these revenues were recorded in fuel, purchased and net interchange power. This net presentation of the mark-to-market and settlement amounts is generally required when physical delivery of contract quantities is no longer probable.

For further information regarding the recognition of revenue, see Note 1E, "Summary of Significant Accounting Policies – Derivative Accounting," to the consolidated financial statements.

E. Derivative Accounting

The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. Non-derivative contracts are recorded at the time of delivery or settlement.

The application of derivative accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, is complex and requires management judgment in the following respects: election and designation of the normal purchases and sales exception, identification of derivatives and embedded derivatives, identifying hedge relationships, assessing and measuring hedge ineffectiveness, and determining the fair value of derivatives. All of these judgments, depending upon their timing and effect, can have a significant impact on NU's consolidated earnings.

The fair value of derivatives is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the company determines whether it is a derivative by using amounts referenced in default provisions and other relevant sections of the contract. The estimated quantities to be served are updated during the term of the contract, and such updates can have a material impact on mark-to-market amounts.

The judgment applied in the election of the normal purchases and sales exception (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery and that the quantities will be used or sold by the business over a reasonable period in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then the normal exception and accrual accounting is terminated and fair value accounting is applied.

Contracts that are hedging an underlying transaction and that qualify as derivatives that hedge exposure to the variable cash flows of a forecasted transaction (cash flow hedges) are recorded on the consolidated balance sheets at fair value with changes in fair value reflected in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. In addition, cash flow hedges impact earnings when hedge ineffectiveness is measured and recorded or when the forecasted transaction being hedged is no longer probable of occurring.

Most of the contracts that comprise or comprised Select Energy's wholesale marketing and competitive generation activities are or were derivatives, and many of our regulated company contracts for the purchase or sale of energy or energy-related products are derivatives. Certain of Select Energy's retail marketing contracts with retail customers were not derivatives, while virtually all contracts Select Energy entered into to supply these customers were derivatives. Select Energy sold those retail marketing and supply contracts to Hess Corporation (Hess) on June 1, 2006.

The Emerging Issues Task Force (EITF) Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as defined in EITF Issue No. 02-3," addresses income statement classification of derivatives that are not related to energy trading activities. In accordance with EITF 03-11, the remaining wholesale marketing contracts, which are marked-to-market derivative contracts are not considered to be held for trading purposes, and sales and purchase activity is reported on a net basis in fuel, purchased and net interchange power.

EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," prohibits recording the initial gains and losses on derivative contracts if their estimated fair values are based on significant non-observable inputs. Based upon the significance of non-observable capacity prices to their valuation, the estimated initial fair values of CL&P's contracts for differences (CfDs) are not recorded on the balance sheet as of December 31, 2007.

For further information regarding the company's derivative contracts, and their accounting, see Note 5, "Derivative Instruments," to the consolidated financial statements.

F. Regulatory Accounting

The accounting policies of the regulated companies conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises and historically reflect the effects of the rate-making process in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation."

The transmission and distribution segments of CL&P, PSNH and WMECO, along with PSNH's generation segment and Yankee Gas's distribution segment, continue to be cost-of-service, rate regulated. Management believes that the application of SFAS No. 71 to those segments continues to be appropriate. Management also believes it is probable that NU's regulated companies will recover their investments in long-lived assets, including regulatory assets. All material net regulatory assets are earning an equity return, except for securitized regulatory assets and the majority of deferred benefit costs, which are not supported by equity. Amortization and deferrals of regulatory assets/(liabilities) are included on a net basis in amortization expense on the accompanying consolidated statements of income/(loss).

Regulatory Assets: The components of regulatory assets are as follows:

(Millions of Dollars)	At December 31, 2007	2006
Securitized assets	$ 907.0	$1,131.1
Deferred benefit costs	201.4	407.4
Income taxes, net	335.5	308.0
Unrecovered contractual obligations	189.9	214.4
Regulatory assets offsetting regulated company derivative liabilities	122.3	75.4
CL&P CTA and SBC undercollections	90.6	100.5
Other regulatory assets	210.4	212.3
Totals	$2,057.1	$2,449.1

Additionally, the regulated companies had $11.9 million and $11.2 million of regulatory costs at December 31, 2007 and 2006, respectively, that were included in deferred debits and other assets - other on the accompanying consolidated balance sheets. These amounts represent regulatory costs that have not yet been approved for recovery by the applicable regulatory agency. Management believes these costs are recoverable in future cost-of-service regulated rates.

Securitized Assets: In March of 2001, CL&P issued $1.4 billion in rate reduction certificates. CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with independent power producers (IPP). The unamortized CL&P securitized asset balance was $468.6 million and $604.5 million at December 31, 2007 and 2006, respectively. CL&P used the remaining proceeds from the issuance of the rate reduction certificates to securitize a portion of its SFAS No. 109, "Accounting for Income Taxes," regulatory asset. The securitized SFAS No. 109 regulatory asset had an unamortized balance of $79.6 million and $102.7 million at December 31, 2007 and 2006, respectively.

In April of 2001, PSNH issued rate reduction bonds in the amount of $525 million. PSNH used the majority of the proceeds from that issuance to buydown its affiliated power contracts with North Atlantic Energy Corporation. The unamortized PSNH securitized asset balance was $272.4 million and $314.7 million at December 31, 2007 and 2006, respectively. In January of 2002, PSNH issued an additional $50 million in rate reduction bonds and used the proceeds from that issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December of 2001. The unamortized PSNH securitized asset balance for the January of 2002 issuance was $0.8 million and $10.9 million at December 31, 2007 and 2006, respectively. The January 2002 rate reduction bonds are expected to be paid in full in the first quarter of 2008.

In May of 2001, WMECO issued $155 million in rate reduction certificates and used the majority of the proceeds from that issuance to buyout an IPP contract. The unamortized WMECO securitized asset balance was $85.6 million and $98.3 million at December 31, 2007 and 2006, respectively.

Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of their associated rate reduction certificates/bonds. All outstanding CL&P rate reduction certificates are scheduled to fully amortize by December 30, 2010, while PSNH rate reduction bonds are scheduled to fully amortize by May 1, 2013, and WMECO rate reduction certificates are scheduled to fully amortize by June 1, 2013.

Deferred Benefit Costs: On December 31, 2006, the company implemented SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." SFAS No. 158 applies to NU's Pension Plan, SERP, and postretirement benefits other than pension (PBOP) Plan and requires an additional benefit liability to be recorded with an offset to accumulated other comprehensive income in shareholders' equity, which is remeasured annually. However, because the regulated companies are cost-of-service rate regulated entities under SFAS No. 71, offsets were recorded as a regulatory asset of $201.4 million at December 31, 2007 and $407.4 million at December 31, 2006 as these amounts have been and continue to be recoverable in cost-of-service regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the regulated companies, as these amounts are also recoverable. The majority of the deferred benefit costs are not in rate base.

Income Taxes, Net: The tax effect of temporary differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions, SFAS No. 109 and FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." Differences in income taxes between SFAS No. 109, FIN 48 and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets which totaled $335.5 million and $308 million at December 31, 2007 and 2006, respectively. For further information regarding income taxes, see Note 1G, "Summary of Significant Accounting Policies – Income Taxes," to the consolidated financial statements.

Unrecovered Contractual Obligations: Under the terms of contracts with the Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC), and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), CL&P, PSNH, and WMECO are responsible for their proportionate share of the remaining costs of the units, including decommissioning. A portion of these amounts, $189.9 million and $214.4 million at December 31, 2007 and 2006, respectively, was recorded as unrecovered contractual obligations regulatory assets. A portion of these obligations for CL&P was securitized in 2001 and was included in securitized regulatory assets. Amounts for WMECO are being recovered along with other stranded costs. Amounts for PSNH were fully recovered by December 31, 2006.

Regulatory Assets Offsetting Regulated Company Derivative Liabilities: The regulatory assets offsetting derivative liabilities relate to the fair value of contracts used to purchase power and other related contracts that will be collected from customers in the future. These amounts totaled $122.3 million and $75.4 million at December 31, 2007 and 2006, respectively. See Note 5, "Derivative Instruments," for further information. This asset is excluded from rate base.

CL&P CTA and SBC Undercollections: The Competitive Transition Assessment (CTA) allows CL&P to recover stranded costs, such as securitization costs associated with the rate reduction bonds, amortization of regulatory assets, and IPP over market costs. The System Benefits Charge (SBC) allows CL&P to recover certain regulatory and energy public policy costs, such as public education outreach costs, hardship protection costs, transition period property taxes and displaced workers protection costs. At December 31, 2007 and 2006, CTA undercollections totaled $54 million and $75.5 million, respectively. At December 31, 2007 and 2006, SBC undercollections totaled $36.6 million and $25 million, respectively.

Other Regulatory Assets: Included in other regulatory assets are the regulatory assets associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143," totaling $40.6 million and $46.4 million at December 31, 2007 and 2006, respectively. Of these amounts, $11.6 million and $13.7 million, respectively, have been approved for future recovery. Management believes that recovery of the remaining regulatory assets is probable.

At December 31, 2007 and 2006, other regulatory assets also included $28.8 million and $31.6 million, respectively, related to losses on reacquired debt, $29.3 million and $32.6 million, respectively, related to environmental costs, $16.1 million and $18.2 million, respectively, related to the buyout and buydown of other IPP contracts, and $95.6 million and $83.5 million, respectively, related to various other items.

Regulatory Liabilities: The components of regulatory liabilities are as follows:

(Millions of Dollars)	At December 31, 2007	2006
Cost of removal	**$262.6**	$290.8
Regulatory liabilities offsetting regulated company derivative assets	**330.4**	294.5
CL&P GSC and FMCC overcollections	**119.2**	108.2
Other regulatory liabilities	**139.6**	115.8
Totals	**$851.8**	$809.3

Cost of Removal: NU's regulated companies currently recover amounts in rates for future costs of removal of plant assets. These amounts, which totaled $262.6 million and $290.8 million at December 31, 2007 and 2006, respectively, are classified as regulatory liabilities on the accompanying consolidated balance sheets. This liability is included in rate base.

Regulatory Liabilities Offsetting Regulated Company Derivative Assets: The regulatory liabilities offsetting derivative assets relate to the fair value of contracts used to purchase power and other related contracts that will benefit ratepayers in the future. These amounts totaled $330.4 million and $294.5 million at December 31, 2007 and 2006, respectively. See Note 5, "Derivative Instruments," for further information. This liability is excluded from rate base.

CL&P GSC and FMCC Overcollections: The Generation Service Charge (GSC) allows CL&P to recover the costs of the procurement of energy for standard service, which includes forward capacity market charges. The Federally Mandated Congestion Charges (FMCC) mechanism allows CL&P to recover the costs of power market rules by the FERC, including Reliability Must Run (RMR) costs. At December 31, 2007 and 2006, GSC and FMCC overcollections totaled $119.2 million and $108.2 million, respectively.

Other Regulatory Liabilities: At December 31, 2007 and 2006, other regulatory liabilities included $20.6 million and $23.8 million, respectively, of prepaid pension and other post employment benefits amounts related to the purchase of Yankee Gas in March of 2000, a $25.6 million liability at December 31, 2006 related to transmission refunds to be provided to customers as a result of the FERC ROE decision, $17.6 million and $18.3 million, respectively, related to PSNH's energy service overcollections, $21.4 million and $6.6 million, respectively, related to CL&P's 50 percent reserve for allowance for funds used during construction (AFUDC) currently recovered in rate base as a result of FERC approved transmission incentives, and $80 million and $41.5 million related to various other items at December 31, 2007 and 2006, respectively.

G. Income Taxes

The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions, SFAS No. 109 and FIN 48. Details of income tax expense/(benefit) related to continuing operations are as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	**$ 89.3**	$ 59.7	$ 21.2
State	**18.9**	(19.1)	6.6
Total current	**108.2**	40.6	27.8
Deferred income taxes, net:			
Federal	**26.2**	(49.7)	(158.6)
State	**(21.4)**	(4.2)	(50.4)
Total deferred	**4.8**	(53.9)	(209.0)
Investment tax credits, net	**(3.6)**	(63.0)	(3.7)
Income tax expense/(benefit)	**$109.4**	$(76.3)	$(184.9)

A reconciliation between income tax expense/(benefit) and the expected tax expense/(benefit) at the statutory rate is as follows:

(Millions of Dollars, except percentages)	For the Years Ended December 31, 2007	2006	2005
Income/(loss) from continuing operations before income tax expense/(benefit)	**$360.9**	$ 62.2	$(436.2)
Expected federal income tax expense/(benefit)	**126.3**	21.7	(152.7)
Tax effect of differences:			
Depreciation	**(6.6)**	(4.0)	(3.5)
Amortization of regulatory assets	**0.2**	13.3	1.8
Investment tax credit amortization (including $59.3 million related to the PLR in 2006)	**(3.6)**	(63.0)	(3.7)
Other federal tax credits	**(3.1)**	(0.3)	—
State income taxes, net of federal impact	**(9.6)**	(16.8)	(47.6)
Excess deferred income taxes - PLR	**—**	(14.7)	—
Deferred tax adjustment - sale to affiliate	**—**	(6.0)	—
Medicare subsidy	**(4.4)**	(5.5)	(6.0)
Tax asset valuation allowance/reserve adjustments	**9.4**	1.4	18.5
Other, net	**0.8**	(2.4)	8.3
Income tax expense/(benefit)	**$109.4**	$(76.3)	$(184.9)
Effective tax rate	**30.3%**	*	42.4%

* Not meaningful.

NU and its subsidiaries file a consolidated federal income tax return and file state income tax returns, with some filing in more than one state. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

In 2000, CL&P requested from the Internal Revenue Service (IRS) a Private Letter Ruling (PLR) regarding the treatment of unamortized investment tax credits (UITC) and excess deferred income taxes (EDIT) related to generation assets that were sold. In 2006, the IRS issued a PLR in response to CL&P's request for a ruling, which held that it would be a violation of tax regulations if the EDIT or UITC are used to reduce customers' rates following the sale of the generation assets. CL&P's UITC and EDIT balances related to generation assets that have been sold totaled $59 million and $15 million, respectively, and $74 million combined. Later in 2006, the Connecticut Department of Public Utility Control (DPUC) determined that the UITC and EDIT amounts were no longer required to be held in their existing accounts. As a result of this determination, the $74 million balance was reflected as a reduction to CL&P's 2006 income tax expense with an increase to CL&P's earnings by the same amount.

Included in 2006 amortization of regulatory assets above is $13 million associated with PSNH's restructuring settlement agreement, which was implemented in 2001. In accordance with the provisions of the restructuring settlement, pre-tax amortization of PSNH non-deductible acquisition costs were $38 million and $5 million in 2006 and 2005, respectively.

The tax effects of temporary differences that give rise to the current and long-term net accumulated deferred tax obligations are as follows:

(Millions of Dollars)	At December 31, 2007	2006
Deferred tax liabilities - current:		
Change in fair value of energy contracts	$ 21.9	$ 18.0
Other	52.2	42.0
Total deferred tax liabilities - current	74.1	60.0
Deferred tax assets - current:		
Change in fair value of energy contracts	11.0	17.3
Other	22.7	26.5
Total deferred tax assets - current	33.7	43.8
Net deferred tax liabilities - current	40.4	16.2
Deferred tax liabilities - long-term:		
Accelerated depreciation and other plant-related differences	967.5	931.0
Employee benefits	167.8	126.7
Regulatory amounts:		
Securitized contract termination costs	167.0	200.3
Other regulatory deferrals	93.9	238.1
Income tax gross-up	194.7	202.4
Derivative assets	111.1	99.5
Other	66.5	39.5
Total deferred tax liabilities - long-term	1,768.5	1,837.5
Deferred tax assets - long-term:		
Regulatory deferrals	192.2	267.9
Employee benefits	280.3	308.0
Income tax gross-up	34.0	39.3
Derivative liability	54.2	12.7
Other	164.6	133.7
Total deferred tax assets - long-term	725.3	761.6
Less: valuation allowance	24.3	23.5
Net deferred tax assets - long-term	701.0	738.1
Net deferred tax liabilities - long-term	1,067.5	1,099.4
Net deferred tax liabilities	$1,107.9	$1,115.6

At December 31, 2007, NU had state net operating loss (NOL) carryforwards of $434.1 million that expire between December 31, 2009 and December 31, 2027 and state credit carryforwards of $61.3 million that expire by December 31, 2012. The NOL carryforward deferred tax asset has been fully reserved by a valuation allowance.

At December 31, 2006, NU had state NOL carryforwards of $350 million that expire between December 31, 2008 and December 31, 2026 and state credit carryforwards of $32.8 million that expire by December 31, 2011. The NOL carryforward deferred tax asset has been fully reserved by a valuation allowance.

Effective on January 1, 2007, NU implemented FIN 48. FIN 48 applies to all income tax positions previously filed in a tax return and income tax positions expected to be taken in a future tax return that have been reflected on the balance sheets. FIN 48 addresses the methodology to be used prospectively in recognizing, measuring and classifying the amounts associated with income tax positions that are deemed to be uncertain, including related interest and penalties. Previously, NU recorded estimates for uncertain tax positions in accordance with SFAS No. 5, "Accounting for Contingencies."

As a result of implementing FIN 48, NU recognized a cumulative effect of a change in accounting principle of $41.8 million as a reduction to the January 1, 2007 balance of retained earnings. The CL&P, PSNH and WMECO reductions/(increases) to the January 1, 2007 balances of retained earnings were $24 million, $(1.6) million and $(0.4) million, respectively. Refer to the accompanying consolidated statements of quarterly financial data (unaudited) that discusses a correction in the company's initial adoption of FIN 48.

Interest and Penalties: Effective on January 1, 2007, NU's accounting policy for the classification of interest and penalties related to FIN 48 is as follows:

- Interest on uncertain tax positions is recorded and classified as a component of other interest expense. NU recorded accrued interest expense of $19.4 million, which is included in the cumulative effect of a change in accounting principle, as of January 1, 2007. For the year ended December 31, 2007, NU recorded interest expense of $2.4 million. At December 31, 2007, $21.8 million of accrued interest expense was recognized on the accompanying consolidated balance sheet.
- No penalties have been recorded under FIN 48. If penalties are recorded in the future, then the estimated penalties would be classified as a component of other income/(loss), net.

Unrecognized Tax Benefits: Upon adoption of FIN 48 on January 1, 2007, NU had unrecognized tax benefits totaling $86.1 million, of which $69.5 million would impact the effective tax rate, if recognized. As of December 31, 2007, NU's unrecognized tax benefits totaled $121.1 million, of which $93 million would impact the effective tax rate, if recognized.

A reconciliation of the activity in unrecognized tax benefits from January 1, 2007 to December 31, 2007 is as follows:

(Millions of Dollars)	
Balance at beginning of year	$ 86.1
Gross increases - current year	25.0
Gross increases - prior year	10.6
Lapse of statute of limitations	(0.6)
Balance at end of year	$121.1

Tax Positions: NU is currently working to resolve all open tax years. It is reasonably possible that one or more of these open tax years could be resolved within the next twelve months. Management estimates that potential resolutions could result in a $2 million to $27 million decrease in unrecognized tax benefits by NU. This estimated change is primarily related to the timing of deducting expenses for book versus tax purposes, which is not expected to have a material impact on earnings.

Tax Years: The following table summarizes NU's tax years that remain subject to examination by major tax jurisdictions at December 31, 2007:

Description	Tax Years
Federal	2002 - 2007
Connecticut	1997 - 2007
New Hampshire	2003 - 2007
Massachusetts	2004 - 2007

H. Other Investments

NU maintains certain other investments at December 31, 2007. These investments included Acumentrics Corporation (Acumentrics), a developer of fuel cell and power quality equipment, and BMC Energy LLC (BMC), an operator of renewable energy projects.

Acumentrics: In July of 2006, Acumentrics was recapitalized and its debt securities held by NU were converted into preferred stock. NU's cost method investment in Acumentrics totaled $0.6 million at both December 31, 2007 and 2006 and is included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

BMC: In 2007 and 2005, based on information that negatively impacted undiscounted cash flow projections and fair value estimates, management determined that the fair value of the note receivable from BMC had declined and that the note was impaired. As a result, NU recorded pre-tax investment write-downs of $0.5 million and $0.8 million in 2007 and 2005, respectively. At December 31, 2007, there was no remaining balance related to BMC.

The BMC investment write-down is included in other income, net on the accompanying consolidated statements of income/(loss). For further information, see Note 1R, "Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

I. Property, Plant and Equipment and Depreciation

The following table summarizes NU's investments in utility plant at December 31, 2007 and 2006 and the average depreciable life at December 31, 2007:

	Average Depreciable Life	At December 31, 2007	2006
	(Years)	(Millions of Dollars)	
Distribution	32.5	**$6,230.3**	$5,950.4
Transmission	45.2	**1,751.1**	1,460.9
Generation	27.3	**590.5**	577.2
Competitive energy	6.1	**18.7**	17.9
Other	15.2	**291.8**	281.5
Total property, plant and equipment		**8,882.4**	8,287.9
Less: Accumulated depreciation		**(2,661.8)**	(2,615.1)
Net property, plant and equipment		**6,220.6**	5,672.8
Construction work in progress		**1,009.3**	569.4
Total property, plant and equipment, net		**$7,229.9**	$6,242.2

The provision for depreciation on utility assets is calculated using the straight-line method based on the estimated remaining useful lives of depreciable plant in-service, adjusted for salvage value and removal costs, as approved by the appropriate regulatory agency, where applicable. Depreciation rates are applied to plant-in-service from the time it is placed in service. When a plant is retired from service, the original cost of the plant is charged to the accumulated provision for depreciation which includes cost of removal less salvage. Cost of removal is classified as a regulatory liability. The depreciation rates for the several classes of utility plant-in-service are equivalent to a composite rate of 3.2 percent in 2007, 2006, and 2005.

J. Equity Method Investments

Regional Nuclear Companies: At December 31, 2007, CL&P, PSNH and WMECO owned common stock in three regional nuclear companies (Yankee Companies). Each of the Yankee Companies owned a single nuclear generating plant which has been decommissioned. NU's ownership interests in the Yankee Companies at December 31, 2007, which are accounted for on the equity method, were 49 percent of CYAPC, 38.5 percent of the YAEC, and 20 percent of the MYAPC. The total carrying value of NU's ownership interests in CYAPC, MYAPC and YAEC, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets and the regulated companies - electric distribution reportable segment, totaled $6.6 million and $9.9 million at December 31, 2007 and 2006, respectively. Earnings related to these equity investments are included in other income, net on the accompanying consolidated statements of income/(loss). For further information, see Note 1R, "Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

For further information, see Note 8E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

Hydro-Quebec: NU parent has a 22.7 percent equity ownership interest in two companies that transmit electricity imported from the Hydro-Quebec system in Canada. NU's investment, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets, totaled $7.6 million and $7.9 million at December 31, 2007 and 2006, respectively.

K. Allowance for Funds Used During Construction

AFUDC is included in the cost of the regulated companies' utility plant and represents the cost of borrowed and equity funds used to finance construction. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of other interest expense, and the AFUDC related to equity funds is recorded as other income on the accompanying consolidated statements of income/(loss).

(Millions of Dollars, except percentages)	For the Years Ended December 31, 2007	2006	2005
AFUDC:			
Borrowed funds	**$17.5**	$13.5	$10.1
Equity funds	**17.4**	13.6	12.3
Totals	**$34.9**	$27.1	$22.4
Average AFUDC rates	**7.6%**	7.5%	7.2%

The regulated companies' average AFUDC rate is based on a FERC-prescribed formula that develops an average rate using the cost of a company's short-term financings as well as a company's capitalization (preferred stock, long-term debt and common equity). The average rate is applied to eligible construction work in progress (CWIP) amounts to calculate AFUDC. Although AFUDC is recorded on 100 percent of CL&P's CWIP for its major transmission projects in southwest Connecticut, 50 percent of this AFUDC is being reserved as a regulatory liability to reflect current rate base recovery for 50 percent of the CWIP as a result of FERC approved transmission incentives.

L. Sale of Customer Receivables

CL&P Receivables Corporation (CRC), a consolidated, wholly-owned subsidiary of CL&P, is permitted to sell up to $100 million of an undivided interest in CL&P's accounts receivable and unbilled revenues to a financial institution. At December 31, 2007, there were $20 million in sales. At December 31, 2006, there were no such sales.

At December 31, 2007 and 2006, amounts sold to CRC by CL&P but not sold to the financial institution totaling $308.2 million and $375.7 million, respectively, were included in investments in securitizable assets on the accompanying consolidated balance sheets. These amounts would be excluded from CL&P's assets in the event of CL&P's bankruptcy.

On July 3, 2007, CL&P extended the bank commitment under the Receivables Purchase and Sale Agreement with CRC and the financial institution through June 30, 2008 and extended the facility termination date to June 21, 2012. CL&P's continuing involvement with the receivables that are sold to CRC and the financial institution is limited to the servicing of those receivables.

The transfer of receivables to the financial institution under this arrangement qualifies for sale treatment under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities – A Replacement of SFAS No. 125."

M. Asset Retirement Obligations

NU implemented FIN 47 on December 31, 2005. FIN 47 requires an entity to recognize a liability for the fair value of an asset retirement obligation (ARO) on the obligation date if the liability's fair value can be reasonably estimated and is conditional on a future event. FIN 47 provides that settlement dates and future costs should be reasonably estimated when sufficient information becomes available and provides guidance on the definition and timing of sufficient information in determining expected cash flows and fair values. Management has identified various categories of AROs, primarily certain assets containing asbestos and hazardous contamination. A fair value calculation, reflecting expected probabilities for settlement scenarios, has been performed.

For the year ended December 31, 2005, the earnings impact of this implementation was recorded as a cumulative effect of accounting change of $1 million, net of tax benefit, related to NU Enterprises. These AROs were transferred with the assets of NGC and Mt. Tom with the sale of the generation business on November 1, 2006. Because the regulated companies are cost-of-service, rate regulated entities, these companies apply regulatory accounting in accordance with SFAS No. 71, and the costs associated with the regulated companies' AROs were included in other regulatory assets at December 31, 2007 and 2006.

The fair value of the AROs was recorded as a liability in deferred credits and other liabilities – other with an offset included in property, plant and equipment on the accompanying consolidated balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation with corresponding credits recorded as accumulated depreciation and ARO liabilities, respectively. For NU's regulated companies where recovery has not yet been formalized, both the depreciation and accretion were recorded as increases to regulatory assets on the accompanying consolidated balance sheets at December 31, 2007 and 2006.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities at December 31, 2007 and 2006:

	At December 31, 2007			
(Millions of Dollars)	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	**$ 2.7**	**$(1.6)**	**$19.6**	**$(21.3)**
Hazardous contamination	**4.5**	**(1.2)**	**13.7**	**(17.3)**
Other AROs	**6.8**	**(3.0)**	**7.3**	**(11.1)**
Total regulated companies' AROs	**$14.0**	**$(5.8)**	**$40.6**	**$(49.7)**

	At December 31, 2006			
(Millions of Dollars)	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	$ 3.8	$(2.1)	$20.1	$(22.1)
Hazardous contamination	6.5	(1.6)	15.9	(20.7)
Other AROs	11.8	(5.5)	10.4	(16.9)
Total regulated companies' AROs	$22.1	$(9.2)	$46.4	$(59.7)

A reconciliation of the beginning and ending carrying amounts of regulated companies' AROs is as follows:

(Millions of Dollars)	2007	2006
Balance at beginning of year	**$(59.7)**	$(60.2)
Liabilities incurred during the year	**(2.8)**	(5.7)
Liabilities settled during the year	**7.3**	1.6
Accretion	**(1.3)**	(0.6)
Changes in estimates	**7.9**	3.7
Revisions in estimated cash flows	**(1.1)**	1.5
Balance at end of year	**$(49.7)**	$(59.7)

Changes in estimates and revisions in estimated cash flows supporting the carrying amounts of AROs include changes in estimated quantities and removal costs, discount rates and inflation rates.

N. Materials and Supplies

Materials and supplies include materials purchased primarily for construction, operation and maintenance (O&M) purposes. Materials and supplies are valued at the lower of average cost or market.

O. Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, any overdraft amounts are reclassified from cash and cash equivalents to accounts payable.

P. Special Deposits

To the extent counterparties require collateral from Select Energy, cash is held on deposit with unaffiliated counterparties and brokerage firms as a part of the total collateral required based on Select Energy's position in the transaction. Select Energy's right to use cash collateral is determined by the terms of the related agreements. Key factors affecting the unrestricted status of a portion of this cash collateral include the financial standing of Select Energy and of NU as its credit supporter.

Special deposits paid to unaffiliated counterparties and brokerage firms totaled $18.9 million and $48.5 million at December 31, 2007 and 2006, respectively. These amounts are recorded as current assets and are included as special deposits on the accompanying consolidated balance sheets.

NU also had amounts on deposit related to four special purpose entities used to facilitate the issuance of rate reduction bonds and certificates. These amounts totaled $43.5 million and $102.5 million at December 31, 2007 and 2006, respectively. In addition, the company had $6.4 million and $11.2 million in other cash deposits held with unaffiliated parties at December 31, 2007 and 2006, respectively, primarily related to CL&P's transmission projects. These amounts are included in deferred debits and other assets - other on the accompanying consolidated balance sheets.

Q. Other Taxes

Certain excise taxes levied by state or local governments are collected by NU from its customers. These excise taxes are accounted for on a gross basis with collections in revenues and payments in expenses. For the years ended December 31, 2007, 2006 and 2005, gross receipts taxes, franchise taxes and other excise taxes of $112.2 million, $114.1 million and $112.7 million, respectively, were included in operating revenues and taxes other than income taxes on the accompanying consolidated statements of income/(loss). Certain sales taxes are also collected by the regulated companies from their customers as agents for state and local governments and are recorded on a net basis with no impact on the accompanying consolidated statements of income/(loss).

R. Other Income, Net

The pre-tax components of other income/(loss) items are as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Other Income:			
Investment income	$22.3	$24.9	$19.1
CL&P procurement fee	—	11.0	17.8
AFUDC - equity funds	17.4	13.6	12.3
Energy Independence Act incentives	9.9	5.5	—
Conservation and load management incentives	7.7	6.5	7.7
Equity in earnings of regional nuclear generating and transmission companies	4.0	0.3	3.3
Gain on sale of Globix investment	—	3.1	—
Other	1.0	0.8	1.4
Total Other Income	62.3	65.7	61.6
Other Loss:			
Investment write-downs	(0.5)	—	(6.9)
Loss on investment in receivables	—	(1.1)	—
Other	(0.2)	(0.2)	(0.2)
Total Other Loss	(0.7)	(1.3)	(7.1)
Total Other Income, Net	$61.6	$64.4	$54.5

Equity in earnings of regional nuclear generating and transmission companies relates to NU's investment in the Yankee Companies and the two Hydro-Quebec transmission companies.

The CL&P procurement fee represents compensation approved by the DPUC associated with Transitional Standard Offer (TSO) supply procurement. The conservation and load management incentives relate to incentives earned if certain energy and demand savings goals are met.

The Energy Independence Act incentives relate to incentives earned under the Act to encourage regulated companies to construct distributed generation, new large-scale generation and implement conservation and load management initiatives to reduce FMCC charges.

S. Supplemental Cash Flow Information

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Cash paid/(received) during the year for:			
Interest, net of amounts capitalized	$261.6	$277.2	$276.7
Income taxes	$496.2	$ 51.3	$ (56.1)
Non-cash investing activities:			
Capital expenditures incurred but not paid	$184.4	$105.2	$ 97.0

Cash paid during the year for income taxes increased as a result of the payment of approximately $400 million in federal and state income taxes in 2007 related to the 2006 sale of the competitive generation business.

T. Marketable Securities

SERP/Non-SERP and Prior Spent Nuclear Fuel Trusts: NU currently maintains two trusts that hold marketable securities. The trusts are used to fund NU's SERP/non-SERP and WMECO's prior period spent nuclear fuel liability. NU's marketable securities are classified as available-for-sale, as defined by SFAS No. 115, "Accounting for Certain Investments and Debt and Equity Securities." At December 31, 2007, changes in the fair value of securities in the SERP/non-SERP trust relating to unrealized losses are considered other than temporary by nature and have been recorded as a pre-tax loss. Changes related to unrealized gains are recorded in accumulated other comprehensive income. Realized gains and losses and unrealized losses related to the SERP and non-SERP assets are included in other income, net, on the consolidated statements of income/(loss). Realized gains, net of realized and unrealized losses, associated with the WMECO spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel trust obligation.

Globix: In 2004, NEON Communications, Inc. (NEON) and Globix Corporation (Globix) announced a merger agreement in which Globix, an unaffiliated publicly owned entity, would acquire NEON for shares of Globix common stock. In connection with the merger, NU recorded a pre-tax write-down of $0.2 million in 2005. After the merger, NU's investment in Globix was recorded as a marketable security, and NU recognized unrealized losses on its investment in accumulated other comprehensive income. Also during 2005, the value of Globix common stock declined, and management reviewed NU's investment in Globix, considering the length and severity of its decline in value, other factors about the company, and management's intentions with respect to holding this investment. Based on these factors, management recorded an additional pre-tax impairment charge of $5.9 million in 2005 to reflect an other-than-temporary impairment.

On April 6, 2006, NU sold its investment in Globix. This sale resulted in net proceeds of approximately $6.7 million and a pre-tax gain of $3.1 million in 2006.

For information regarding marketable securities, see Note 10, "Marketable Securities," to the consolidated financial statements.

U. Provision for Uncollectible Accounts

NU maintains a provision for uncollectible accounts to record its receivables at an estimated net realizable value. This provision is determined based upon a variety of factors, including applying an estimated uncollectible account percentage to each receivable aging category, historical collection and write-off experience and management's assessment of collectibility from individual customers. Management reviews at least quarterly the collectibility of the receivables, and if circumstances change, collectibility estimates are adjusted accordingly. Receivable balances are written-off against the provision for uncollectible accounts when these balances are deemed to be uncollectible.

In November of 2006, the DPUC issued an order allowing CL&P and Yankee Gas to accelerate the recovery of uncollectible hardship accounts receivable outstanding for greater than 90 days. At December 31, 2007, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $24 million and $8 million, respectively, with corresponding regulatory assets as these amounts are probable of recovery. At December 31, 2006, these amounts totaled $17 million and $8 million, respectively. Prior to the order, any write-offs of these amounts were deferred for recovery at the time of write-off. The CL&P reserve offsets amounts sold to CRC by CL&P but not sold to the financial institution, which are classified as investments in securitizable assets on the accompanying consolidated balance sheets. The Yankee Gas reserve offsets receivables.

2. Restructuring and Impairment Charges

NU Enterprises recorded $0.2 million, $27.6 million and $69.2 million of pre-tax restructuring and impairment charges for the years ended December 31, 2007, 2006 and 2005, respectively, relating to the decision to exit NU Enterprises. The amounts related to continuing operations are included as restructuring and impairment charges on the consolidated statements of income/(loss) with the remainder included in discontinued operations. These charges are included as part of the NU Enterprises reportable segment in Note 16, "Segment Information," to the consolidated financial statements. A summary of these pre-tax charges is as follows:

	Years Ended December 31,		
(Millions of Dollars)	2007	2006	2005
Wholesale Marketing:			
Impairment charges	$ —	$ —	$ 9.7
Restructuring charges	—	0.3	6.7
Subtotal	—	0.3	16.4
Retail Marketing:			
Impairment charges	—	—	9.2
Restructuring charges	—	6.6	—
Subtotal	—	6.6	9.2
Competitive Generation:			
Impairment charges	—	0.3	1.5
Restructuring charges	—	15.8	—
Subtotal	—	16.1	1.5
Energy Services and Other:			
Impairment charges	—	—	39.1
Restructuring charges	0.2	4.6	3.0
Subtotal	0.2	4.6	42.1
Total restructuring and impairment charges	0.2	27.6	69.2
Restructuring and impairment charges included in discontinued operations	—	19.1	33.1
Total restructuring and impairment charges included in continuing operations	$0.2	$ 8.5	$36.1

Wholesale Marketing: In 2005, $9.7 million of impairment charges were recorded related to the impairment of plant assets and goodwill totaling $3.2 million related to Select Energy New York, Inc. (SENY) operations. In 2006 and 2005, $0.3 million and $6.7 million, respectively, of restructuring charges were recorded for consulting fees, legal fees and employee-related and other costs.

Retail Marketing: In 2005, an exclusivity agreement intangible asset totaling $7.2 million and a customer list asset totaling $2 million relating to the retail marketing business were written off as a result of an impairment analysis performed. In 2006, NU Enterprises completed the sale of the retail marketing business and recorded restructuring charges of $6.6 million for consulting fees, legal fees and employee-related and other costs.

Competitive Generation: In 2005, $1.5 million of impairment charges related to plant assets were recorded as a result of an impairment analysis performed. In 2006, $0.3 million of impairment charges were recorded for the competitive generation business related to certain long-lived assets that were no longer recoverable. In 2006, restructuring charges of $15.8 million were recorded for consulting fees, legal fees, sale-related environmental fees and employee-related and other costs.

Energy Services and Other: In 2005, $29.1 million of goodwill, $9.2 million of intangible assets and $0.8 million of certain fixed assets were impaired. In 2007, 2006 and 2005, $0.2 million, $3.6 million and $3 million, respectively, of restructuring charges were recorded for consulting fees, legal fees and employee-related and other costs. In addition, in 2006, restructuring charges included $1 million related to the termination of NU parent's guarantee of SESI's performance under government contracts.

The following table summarizes the liabilities related to restructuring costs which are recorded in accounts payable and other current liabilities on the accompanying consolidated balance sheets since the decision to exit NU Enterprises in 2005:

(Millions of Dollars)	Employee-Related Costs	Professional and Other Fees	Total
Restructuring liability as of January 1, 2005	$ —	$ —	$ —
Costs incurred	2.3	7.4	9.7
Cash payments and other deductions/reversals	(0.5)	(3.2)	(3.7)
Restructuring liability as of December 31, 2005	1.8	4.2	6.0
Costs incurred	3.3	24.0	27.3
Cash payments and other deductions/reversals	(3.7)	(25.9)	(29.6)
Restructuring liability as of December 31, 2006	1.4	2.3	3.7
Costs incurred	—	0.2	0.2
Cash payments and other deductions/reversals	(1.4)	(2.2)	(3.6)
Restructuring liability as of December 31, 2007	**$ —**	**$ 0.3**	**$ 0.3**

3. Assets Held for Sale and Discontinued Operations

In 2005, NU decided to exit the NU Enterprises businesses. A summary of the NU Enterprises businesses held for sale status as of December 31, 2007 and 2006, as well as the discontinued operations status for all years presented including date sold, is as follows:

	Held for Sale Status as of December 31, 2007	December 31, 2006	Discontinued Operations	Sale Date
Wholesale Marketing	**No**	No	No	Not Sold
Retail Marketing	**Sold**	Sold	No	June 2006
NGC (including certain components of NGS)	**Sold**	Sold	Yes	November 2006
Mt. Tom	**Sold**	Sold	Yes	November 2006
NGS	**No**	No	No	Not Sold
SESI	**Sold**	Sold	Yes	May 2006
Former Woods Electrical – portion sold	**Sold**	Sold	Yes	April 2006
Former Woods Electrical – remaining contracts	**No**	No	No	Wound Down in 2007
Woods Network	**Sold**	Sold	Yes	November 2005
Boulos	**No**	No	No	Not Sold
SECI – New Hampshire location	**Sold**	Sold	Yes	November 2005
SECI – Massachusetts location	**Sold**	Sold	Yes	March 2006
SECI – remaining contracts	**No**	No	Yes	Wound Down in 2007

Assets Held for Sale: At December 31, 2007, management continues to believe the remaining wholesale marketing business, NGS, and Boulos do not meet the held for sale criteria under applicable accounting guidance and therefore continue to be included in continuing operations. At December 31, 2006, Select Energy had current derivative assets and liabilities totaling $0.2 million and $0.1 million, respectively, related to administrative agreements for one remaining sourcing contract and a small number of retail gas sales contracts, which are included in assets held for sale and liabilities of assets held for sale on the accompanying consolidated balance sheets.

Discontinued Operations: In 2007, the remaining contracts of SECI were wound down, and all of SECI meets the criteria requiring discontinued operations presentation for all years presented. NU's consolidated statements of income/(loss) present NGC, Mt. Tom, SESI, Woods Network, and a portion of former Woods Electrical as discontinued operations. These businesses, along with the New Hampshire and Massachusetts locations of SECI, were sold in 2006 and 2005. Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified in income from discontinued operations on the consolidated statements of income/(loss), and all prior years are reclassified. In the second quarter of 2007, the remaining contracts of former Woods Electrical were completed. The results of these contracts were not material for discontinued operations presentation. The retail marketing business is not presented as discontinued operations because separate financial information for certain periods is not available for this business.

Summarized financial information for the discontinued operations is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Operating revenue	**$1.3**	$180.7	$377.9
Income before income taxes	**0.4**	31.3	11.7
Gains/(losses) from sale/disposition of discontinued operations	**2.1**	504.3	(1.1)
Income tax expense	**1.9**	198.0	6.2
Net income	**0.6**	337.6	4.4

In 2007, gains/(losses) from sale/disposition of discontinued operations of $2.1 million primarily relates to the favorable resolution of legal and contract issues from businesses sold of $4.2 million, partially offset by charges related to the sale of the competitive generation business, including a $1.9 million charge resulting from a purchase price adjustment from the sale of the competitive generation business recorded in the first quarter of 2007. The 2006 gains/(losses) on sale/disposition of discontinued operations of $504.3 million relates to the gain on the sale of NGC and Mt. Tom of $511.1 million and a $1.6 million gain on the sale of the Massachusetts location of SECI, partially offset by an $8.4 million loss on the sale of SESI. The sale of a portion of the former Woods Electrical had a de minimis impact on earnings in 2006. In addition, in 2006, NU recorded a pre-tax loss on the sale of SENY of $0.3 million, which is recorded as other operating expenses as part of continuing operations on the consolidated statement of income/(loss). The 2005 loss on sale/disposition of discontinued operations of $1.1 million consists of $0.8 million and $0.3 million in losses on the sales of Woods Network and the New Hampshire location of SECI, respectively. Included in the 2006 discontinued operations is an approximately $11 million pre-tax loss related to legal and contract issues from businesses sold.

Included in the 2007 income tax expense amount above is a $0.8 million charge recognized to adjust the estimated income tax accrual for actual taxes paid on the gains related to businesses sold in 2006.

No intercompany revenues were included in discontinued operations for the year ended December 31, 2007. Included in discontinued operations are $161 million and $222.2 million for the years ended December 31, 2006 and 2005, respectively, of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of these amounts, $160.7 million and $209.7 million, respectively, represent revenues on intercompany contracts between the generation operations of NGC and Mt. Tom and Select Energy. NGC's and Mt. Tom's revenues and earnings related to these contracts are included in discontinued operations while Select Energy's related expenses and losses are included in continuing operations. Select Energy's obligation to NGC and Mt. Tom ended at the time of sale in 2006.

At December 31, 2007, NU did not have or expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

4. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by the operating companies is subject to periodic approval by either the FERC or by their respective state regulators. On December 12, 2007, the FERC granted authorization to allow CL&P and WMECO to incur total short-term borrowings up to a maximum of $450 million and $200 million, respectively, effective as of December 31, 2007, through December 31, 2009. By rule, the FERC has exempted all holding company money pools from active regulation.

Between January 1, 2007 and March 30, 2007, PSNH was authorized by the New Hampshire Public Utilities Commission (NHPUC) to incur short-term borrowings up to $100 million. In an order dated March 30, 2007, the NHPUC authorized PSNH to incur short-term borrowings up to a maximum of 10 percent of net fixed plant plus an additional 3 percent through December 31, 2007. In an order dated August 3, 2007, the NHPUC increased the amount of short-term borrowings to a maximum of 10 percent of net fixed plant plus a fixed amount of $35 million through December 31, 2008, or until PSNH has utilized its remaining long-term debt authorization. At December 31, 2007, this amount totaled $162.1 million. As a result of this NHPUC jurisdiction over short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings.

The charter of CL&P contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. In November of 2003, CL&P obtained authorization from its preferred stockholders for a ten-year period expiring in March of 2014 to issue unsecured indebtedness with a maturity of less than 10 years in excess of the 10 percent of total capitalization limitation in CL&P's charter, provided that all unsecured indebtedness would not exceed 20 percent of total capitalization. On March 18, 2004, the SEC approved this change in CL&P's charter. As of December 31, 2007, CL&P was permitted to incur $765.7 million of additional unsecured debt under this provision.

Regulated Companies Credit Agreement: CL&P, PSNH, WMECO, and Yankee Gas are parties to a five-year unsecured revolving credit facility for $400 million which expires on November 6, 2010. CL&P may draw up to $200 million under this facility, with PSNH, WMECO and Yankee Gas able to draw up to $100 million each, subject to the $400 million maximum borrowing limit. This total commitment may be increased to $500 million at the request of the borrowers, subject to lender approval. Under this facility, each company may borrow on a short-term basis or on a long-term basis, subject to regulatory approval. There were $45 million of long-term borrowings by Yankee Gas outstanding under this facility at December 31, 2007. There were $10 million and $27 million in short-term borrowings by PSNH and Yankee Gas, respectively, outstanding under this facility at December 31, 2007. The weighted-average interest rate on these short-term borrowings at December 31, 2007 was 7.25 percent. At December 31, 2006, there were no borrowings outstanding under this facility.

NU Parent Credit Agreement: Effective December 31, 2006, NU reduced the total commitments under its 5-year unsecured revolving credit agreement from $700 million to $500 million, which may be increased at NU's request to $600 million, subject to lender approval. The decrease in the total commitment amount also resulted in a reduction in the letter of credit (LOC) commitment amount from $550 million to $500 million. Subject to the advances outstanding, LOCs may be issued for periods up to 364 days in the name of NU or any of its subsidiaries, including Select Energy. This agreement expires on November 6, 2010.

Under this facility, NU can borrow either on a short-term or a long-term basis. At December 31, 2007, NU had $42 million in borrowings outstanding under this facility. The weighted-average interest rate on amounts outstanding under these credit agreements on December 31, 2007 was 7.25 percent. At December 31, 2006, there were no borrowings outstanding under this facility. There were $27 million and $67.5 million in LOCs outstanding at December 31, 2007 and 2006, respectively.

Under the regulated companies' and NU parent credit agreements, NU and the regulated companies may borrow at variable rates plus an applicable margin based upon the higher of Standard and Poor's (S&P) or Moody's Investors Service (Moody's) credit ratings assigned to the borrower.

In addition, NU and the regulated companies must comply with certain financial and non-financial covenants, including but not limited to, a consolidated debt to capitalization ratio. As parties to the credit agreements, NU and the regulated companies currently are and expect to remain in compliance with these covenants.

Amounts outstanding under these credit facilities, excluding the $45 million of long-term borrowings by Yankee Gas, are classified as current liabilities as notes payable to banks on the accompanying consolidated balance sheets as management anticipates that all borrowings under these credit facilities will be outstanding for no more than 364 days at one time.

Other Credit Facility: On May 14, 2007, Boulos renewed its $6 million line of credit, which now expires on June 30, 2008. This credit facility limits Boulos' ability to pay dividends if borrowings are outstanding and limits access to the NU Money Pool (Pool) for additional borrowings. At December 31, 2007 and 2006, there were no borrowings under this credit facility.

5. Derivative Instruments

Contracts that are derivatives and do not meet the requirements to be treated as a cash flow hedge or normal purchase or normal sale are recorded at fair value with changes in fair value included in earnings. For those contracts that meet the definition of a derivative and meet the cash flow hedge requirements, including those related to initial and ongoing documentation, the contract is recorded at fair value and the changes in the fair value of the effective portion of those contracts are recognized in accumulated other comprehensive income. Cash flow hedges include forward interest rate swap agreements on proposed debt issuances. When a cash flow hedge is settled, the settlement amount is recorded in accumulated other comprehensive income and is amortized into earnings over the term of the debt. Cash flow hedges impact net income when the hedge ineffectiveness is measured and recorded, or when the forecasted transaction being hedged is no longer probable of occurring. Derivative contracts designated as fair value hedges and the items they are hedging are both recorded at fair value with changes in fair value of both items recognized in earnings. Derivative contracts that meet the requirements of a normal purchase or sale, and are so designated, are recognized in revenues or expenses, as applicable, when the quantity of the contract is delivered. The change in fair value of a normal purchase or sale derivative contract is not included in earnings.

The fair value of the company's derivative contracts may not represent amounts that will be realized. On the accompanying consolidated balance sheets at December 31, 2007 and 2006, these amounts are recorded as current or long-term derivative assets or liabilities and are summarized as follows:

	At December 31, 2007				
	Assets		Liabilities		
(Millions of Dollars)	Current	Long-Term	Current	Long-Term	Net Total
NU Enterprises:					
Wholesale	$ 36.2	$ 7.2	$(64.9)	$ (72.5)	$ (94.0)
Regulated Companies – Gas:					
Supply	0.2	—	—	—	0.2
Interest Rate Hedging	0.9	—	—	—	0.9
Regulated Companies – Electric:					
Supply/Stranded Costs	59.8	290.8	(6.7)	(136.0)	207.9
Interest Rate Hedging	3.3	—	—	—	3.3
NU Parent:					
Interest Rate Hedging	5.1	—	—	—	5.1
Totals	$105.5	$298.0	$(71.6)	$(208.5)	$123.4

	At December 31, 2006				
	Assets		Liabilities		
(Millions of Dollars)	Current	Long-Term	Current	Long-Term	Net Total
NU Enterprises:					
Wholesale	$43.6	$ 22.3	$ (82.3)	$(110.1)	$(126.5)
Retail	0.2	—	(0.1)	—	0.1
Regulated Companies – Gas:					
Supply	0.1	—	(0.2)	—	(0.1)
Regulated Companies – Electric:					
Supply/Stranded Costs	45.0	249.5	(43.2)	(32.0)	219.3
NU Parent:					
Interest Rate Hedging	—	—	—	(6.5)	(6.5)
Totals	$88.9	$271.8	$(125.8)	$(148.6)	$ 86.3

The 2006 amounts in the table above include retail marketing current derivative assets and liabilities of $0.2 million and $0.1 million, respectively, which are included in assets held for sale and liabilities of assets held for sale on the accompanying consolidated balance sheets.

For the regulated companies, except for existing interest rate swap agreements, offsetting regulatory assets or liabilities are recorded for the changes in fair value of their contracts, as these contracts were part of the stranded costs or are current regulated operating costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates.

A summary of the mark-to-market amounts for NU Enterprises' wholesale and retail marketing (through the June 2006 sale date) and competitive generation businesses (through the November 2006 sale date) included on the accompanying consolidated statements of income/(loss) for the years ended December 31, 2007, 2006 and 2005 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2007	2006	2005
Operating revenues	$ —	$ 7.4	$ 17.3
Fuel, purchased and net interchange power	6.4	24.7	420.0
Other operating expenses	—	47.6	—
Discontinued operations	—	11.5	(15.5)

The business activities of NU Enterprises that result in the recognition of derivative assets result in exposures to credit risk of energy marketing and trading counterparties. At December 31, 2007, Select Energy had $43.4 million of derivative assets from wholesale activities that are exposed to counterparty credit risk, a significant portion of which is contracted with multiple creditworthy, rated public entities.

NU Enterprises – Wholesale: Certain electric derivative contracts are part of the remaining wholesale marketing business. These contracts include wholesale short-term and long-term electricity supply and sales contracts, which include a contract to sell electricity to a utility under full requirements contracts that expires on May 31, 2008 (four other similar contracts expired on May 31, 2007), and a contract to sell electricity to the New York Municipal Power Agency (NYMPA) (an agency that is comprised of municipalities) that expires in 2013. The fair value of the contracts was determined using prices from external sources through 2011 and for on-peak in 2012 and generally using models based on natural gas prices and a heat-rate conversion factor to electricity for off-peak in 2012 and subsequent periods.

The decision to exit the wholesale marketing business changed management's conclusion regarding the likelihood that these wholesale marketing contracts would result in physical delivery to customers and resulted in a change in the first quarter of 2005 from accrual accounting to mark-to-market accounting for the wholesale marketing contracts. For the years ended December 31, 2007, 2006 and 2005, NU recorded pre-tax charges of $7.4 million, $11.7 million and $425.4 million in fuel, purchased and net interchange power related to these contracts. These charges are comprised of the following items:

- Charges of $7.4 million, $10.9 million and $419 million for the years ended December 31, 2007, 2006 and 2005, respectively, associated with the mark-to-market on, and changes in, the fair value of certain long-dated wholesale electricity contracts in New England, New York and PJM and contracts to purchase generation products in New York.
- A charge of $0.8 million for the year ended December 31, 2006 related to the fair value of certain asset-specific sales and forward sales of electricity at hub points for generation contracts. These contracts expired on December 31, 2006.
- A benefit of $30 million for the year ended December 31, 2005 associated with contracts previously designated as wholesale that were redesignated to support the retail marketing business.
- A charge of $36.4 million for the year ended December 31, 2005 for contract asset write-offs and a contract termination payment in March of 2005.

Included in the mark-to-market on long-term wholesale electricity contracts is a $12.5 million pre-tax mark-to-market charge for the year ended December 31, 2005 related to an intercompany contract between Select Energy and CL&P. This contract was included in the portfolio of contracts Select Energy assigned to a third-party wholesale power marketer, and Select Energy stopped serving CL&P on December 31, 2005. This contract was part of CL&P's stranded costs, and benefits received by CL&P under this contract were provided to CL&P's ratepayers in the form of lower-than-market standard offer service rates.

A $2.8 million pre-tax mark-to-market charge in 2005 was recorded as fuel, purchased and net interchange power by Select Energy for the intercompany contract between Select Energy and WMECO for default service from April to June of 2005. WMECO's benefits under this contract were provided to its ratepayers in the form of lower-than-market default service rates. These charges were not eliminated in consolidation because on a consolidated basis NU retained the over-market obligation to the ratepayers of CL&P and WMECO.

In addition to the charges described above, NU recorded a benefit of $1 million to fuel, purchased and net interchange power related to wholesale marketing contracts for the year ended December 31, 2007 and $4.5 million and $8.5 million of charges related to wholesale and retail marketing contracts, respectively, for the year ended December 31, 2006. Similar amounts for 2005 are a charge of $43.7 million and a benefit of $12.7 million for wholesale and retail marketing contracts, respectively.

Regulated Companies – Gas – Supply: Yankee Gas's supply derivatives consist of peaking supply arrangements to serve winter load obligations and firm retail sales contracts with options to curtail delivery. These contracts are subject to fair value accounting as these contracts are derivatives that cannot be designated as normal purchases and sales because of the optionality in the contract terms. An offsetting regulatory liability and an offsetting regulatory asset were recorded for these amounts as management believes that these costs will be refunded/recovered in rates.

Regulated Companies – Gas – Interest Rate Hedging: In December of 2007, Yankee Gas entered into a forward interest rate swap agreement to hedge the interest cash outflows associated with its proposed $100 million September of 2008 debt issuance. The interest rate swap is based on a 10-year LIBOR swap rate and matches the index used for the debt issuance. As a cash flow hedge, at December 31, 2007, the fair value of the hedge is recorded as a $0.9 million derivative asset on the consolidated balance sheet with an offsetting amount included in accumulated other comprehensive income.

Regulated Companies – Electric – Supply/Stranded Costs: CL&P has contracts with two independent power producers (IPP) to purchase power that contain pricing provisions that are not clearly and closely related to the price of power and therefore do not qualify for the normal purchases and sales exception. The fair values of these derivatives at December 31, 2007 included a derivative asset with a fair value of $311.2 million and a derivative liability with a fair value of $31.8 million. An offsetting regulatory liability and an offsetting regulatory asset were recorded, as these contracts are part of stranded costs, and management believes that these costs will continue to be recovered or refunded in cost-of-service, regulated rates. At December 31, 2006, the fair values of these derivatives included a derivative asset with a fair value of $289.6 million and a derivative liability with a fair value of $35.6 million.

CL&P has entered into Financial Transmission Rights contracts and bilateral basis swaps to limit the congestion costs associated with its standard offer contracts. An offsetting regulatory asset or liability has been recorded as management believes that these costs will be recovered or refunded in rates. At December 31, 2007, the fair value of these contracts was recorded as a derivative asset of $1.4 million and a derivative liability of $1.3 million on the accompanying consolidated balance sheets. At December 31, 2006, the fair value of those contracts was recorded as a derivative asset of $4.9 million and a derivative liability of $0.4 million on the accompanying consolidated balance sheets.

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August of 2007 the DPUC approved two CL&P contracts associated with the capacity of two generating projects to be built or modified. The DPUC also approved two capacity-related contracts entered into by The United Illuminating Company (UI), one with a generating project to be built and one with a new demand response project. The total capacity of these four projects is expected to be approximately 787 megawatts (MW). The contracts, referred to as CfDs, obligate the utilities' customers to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent to CL&P and 20 percent to UI. The ultimate cost to CL&P under the contracts will depend on the capacity prices that the projects receive in the ISO-NE capacity markets. Due to the significance of the non-observable capacity prices associated with modeling the fair values of these derivative contracts, their initial negative fair values at inception of approximately $100 million have not been reflected in the accompanying consolidated financial statements. At December 31, 2007, the changes in fair value of these CfDs since inception are recorded as a $107.1 million derivative liability on the consolidated balance sheet. A derivative asset of $20.8 million has been recorded to reflect UI's 20 percent share of these amounts and the change in fair value of one of the CfD contracts. An offsetting regulatory asset and liability for the remaining 80 percent of the changes in fair value of the contracts since inception has been recorded as management believes these amounts will be recovered or refunded in cost-of-service, regulated rates. On October 5, 2007, NRG Energy, Inc. (NRG) filed in New Britain Superior Court an appeal of the DPUC's decision selecting the CfDs. This appeal was taken into consideration in valuing the CfDs and had the effect of reducing the net negative derivative values by approximately $215 million at December 31, 2007. On February 13, 2008, the New Britain Superior Court judge denied NRG's appeal. The effect of this denial will be reflected as an increase in negative derivative values in the first quarter of 2008.

PSNH has electricity procurement contracts that are derivatives. The fair value of these contracts is calculated based on market prices and is recorded as derivative assets of $1.5 million and derivative liabilities of $2.5 million at December 31, 2007. At December 31, 2006, the fair value was recorded as a derivative liability of $28.4 million. An offsetting regulatory liability/asset was recorded as management believes that these costs will be refunded/recovered in rates as the energy is delivered.

In 2007, PSNH entered into a contract to assign transmission rights to a Hydro-Quebec direct current line in exchange for two energy call options which expire in 2010. These energy call options are derivatives that do not qualify for the normal purchases and sales exception and are accounted for at fair value based on market prices. At December 31, 2007, the options were recorded as a short-term derivative asset of $3.6 million and a long-term derivative asset of $12.1 million. An offsetting regulatory liability was recorded, as the benefit of this arrangement will be refunded to customers in rates.

At December 31, 2006, PSNH had a contract to purchase oil that was a derivative, the fair value of which was recorded as a derivative liability of $10.8 million. An offsetting regulatory asset was recorded as management believes that this cost will be recovered in rates through a deferral mechanism that tracks generation revenues and costs. This contract expired in 2007.

Regulated Companies – Electric – Interest Rate Hedging: In December of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest cash outflows associated with two proposed debt issuances of $150 million each in November of 2008. Also, in December of 2007, PSNH entered into a forward interest rate swap agreement to hedge the interest cash outflows associated with its proposed $110 million March of 2008 debt issuance. The interest rate swaps are based on a 10-year LIBOR swap rate and match the index used for the debt issuances. As cash flow hedges, at December 31, 2007, the fair value of these hedges was recorded as a $3.3 million derivative asset on the consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

NU Parent – Interest Rate Hedging: In March of 2003, to manage the interest rate characteristics of the company's long-term debt, NU parent entered into a fixed to floating interest rate swap on its $263 million, 7.25 percent fixed rate note that matures on April 1, 2012. Under fair value hedge accounting, the changes in fair value of the swap and the interest component of the hedged long-term debt instrument are recorded in interest expense, which generally offset each other in the consolidated statement of income/(loss). The cumulative change in the fair value of the swap and the long-term debt is recorded as a derivative asset and an increase to long-term debt of $4.2 million at December 31, 2007. At December 31, 2006, this amount was recorded as a derivative liability and a decrease to long-term debt of $6.5 million.

In December of 2007, NU parent entered into a forward interest rate swap agreement to hedge the interest cash outflows associated with its proposed debt issuance of $200 million in June of 2008. The interest rate swap is based on a 5-year LIBOR swap rate and matches the index used for the debt issuance. As a cash flow hedge at December 31, 2007, the fair value of the hedge is recorded as a $0.9 million derivative asset on the consolidated balance sheet with an offsetting amount included in accumulated other comprehensive income.

6. Employee Benefits

A. Pension Benefits and Postretirement Benefits Other Than Pensions

On December 31, 2006, NU implemented SFAS No. 158, which applies to NU's Pension Plan, SERP, and PBOP Plan and required NU to record the funded status of these plans based on the projected benefit obligation (PBO) for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan on the consolidated balance sheets at December 31, 2007 and 2006. SFAS No. 158 requires the additional liability to be recorded with an offset to accumulated other comprehensive income in shareholders' equity. This amount is remeasured annually, or as circumstances dictate. At December 31, 2007 and 2006, NU recorded an after-tax benefit/(charge) totaling $8.6 million and $(4.4) million, respectively, to accumulated other comprehensive income for its unregulated subsidiaries. However, because the regulated companies are cost-of-service, rate regulated entities under SFAS No. 71, regulatory assets were recorded in the amount of $201.4 million and $407.4 million, respectively, as these benefits expense amounts have been and continue to be recoverable in cost-of-service, regulated rates. Regulatory accounting was also applied to the portions of the NUSCO costs that support the regulated companies, as these amounts are also recoverable.

Pension Benefits: NU's subsidiaries participate in a uniform non-contributory defined benefit retirement plan (Pension Plan) covering substantially all regular NU employees. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. NU uses a December 31st measurement date for the Pension Plan. Pension expense affecting earnings is as follows:

(Millions of Dollars)	For the Years Ended December 31, 2007	2006	2005
Total pension expense	**$17.1**	$50.2	$54.2
Income/(expense) capitalized as utility plant	**1.0**	(11.5)	(11.5)
Total pension expense, net of amounts capitalized	**$18.1**	$38.7	$42.7

Total pension expense above includes pension curtailments and termination (benefits)/expense of $(0.3) million, $(2.5) million and $11.7 million in 2007, 2006 and 2005, respectively.

Pension Curtailments and Termination Benefits: In December of 2005, a new program was approved allowing then current employees to elect to receive retirement benefits under a new 401(k) benefit rather than under the Pension Plan. The approval of the new plan resulted in recording an estimated pre-capitalization, pre-tax curtailment expense of $6.2 million in 2005, as a certain number of employees were expected to elect the new 401(k) benefit, resulting in a reduction in aggregate estimated future years of service under the Pension Plan. Because the predicted level of elections of the new benefit did not occur, NU recorded a pre-capitalization, pre-tax reduction in the curtailment expense of $3.6 million in 2006.

As a result of its corporate reorganization in 2005, NU recorded a combined pre-capitalization, pre-tax curtailment expense and related termination benefits for the Pension Plan totaling $5.5 million. Based on a revised estimate of expected head count reductions in 2006, NU recorded an adjustment to the curtailment and related termination benefits. This adjustment resulted in a pre-capitalization, pre-tax reduction in the curtailment expense of $1.2 million and an increase in termination benefits expense of $2.3 million totaling a net $1.1 million in additional pension expense. NU recorded an additional pre-capitalization, pre-tax reduction in termination benefit expense of $0.3 million in 2007.

Pension Plan COLA: On May 4, 2007, NU's Board of Trustees approved a cost of living adjustment (COLA) that increased retiree pension benefits for certain participants in the Pension Plan. The COLA was announced on May 8, 2007 at the annual meeting of NU's shareholders, which resulted in a plan amendment in 2007 and a remeasurement of the Pension Plan's benefit obligation as of May 8, 2007.

The COLA increased the Pension Plan's benefit obligation by $40 million and was reflected as a prior service cost and as a decrease in the funded status of the Pension Plan. This amount will be amortized over a 12-year period representing average remaining service lives of employees.

Market-Related Value of Pension Plan Assets: NU bases the actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a four-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 and are included in actuarial gains and losses. Since the market-related valuation calculation recognizes gains or losses over a four-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

SERP: NU has maintained a SERP since 1987. The SERP provides its eligible participants who are officers of NU with benefits that would have been provided to them under NU's retirement plan if certain Internal Revenue Code and other limitations were not imposed.

For information regarding SERP investments that are used to fund the SERP liability, see Note 10, "Marketable Securities," to the consolidated financial statements.

PBOP: NU's subsidiaries provide certain health care benefits, primarily medical and dental, and life insurance benefits through a PBOP Plan. These benefits are available for employees retiring from NU who have met specified service requirements. For current employees and certain retirees, the total benefit is limited to two times the 1993 per retiree health care cost. These costs are charged to expense over the estimated work life of the employee. NU uses a December 31st measurement date for the PBOP Plan.

NU annually funds postretirement costs through external trusts with amounts that have been and will continue to be recovered in rates and that are tax deductible. Currently, there are no pending regulatory actions regarding postretirement benefit costs.

PBOP Curtailments and Termination Benefits: NU recorded an estimated $3.7 million pre-tax curtailment expense at December 31, 2005 relating to its corporate reorganization. NU also accrued a $0.5 million pre-tax termination benefit at December 31, 2005 relating to certain benefits provided under the terms of the PBOP Plan. Based on refinements to its estimates, NU recorded an adjustment to the curtailment and related termination benefits in 2006. This adjustment resulted in a pre-capitalization, pre-tax reduction in the curtailment expense of $2.2 million and an increase to termination benefits of $0.3 million in 2006.

The following table represents information on the plans' benefit obligations, fair values of plan assets, and funded status:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	**2007**	2006	**2007**	2006	**2007**	2006
Change in benefit obligation						
Benefit obligation at beginning of year	**$(2,334.6)**	$(2,286.2)	**$(34.0)**	$(35.1)	**$(469.9)**	$(493.8)
Service cost	**(47.0)**	(49.4)	**(0.8)**	(1.1)	**(7.4)**	(8.3)
Interest cost	**(136.4)**	(129.7)	**(1.9)**	(1.9)	**(25.7)**	(27.3)
Actuarial gain/(loss)	**178.4**	58.3	**2.6**	2.1	**3.3**	23.4
Prior service cost	**(40.0)**	—	**—**	—	**—**	—
Federal subsidy on benefits paid	**—**	—	**—**	—	**(3.8)**	(3.2)
Benefits paid – excluding lump sum payments	**122.2**	116.1	**2.0**	2.0	**43.9**	39.9
Benefits paid – lump sum payments	**0.2**	—	**—**	—	**—**	—
Curtailment/impact of plan changes	**—**	(41.4)	**—**	—	**—**	(0.3)
Termination benefits	**0.3**	(2.3)	**—**	—	**—**	(0.3)
Benefit obligation at end of year	**$(2,256.9)**	$(2,334.6)	**$(32.1)**	$(34.0)	**$(459.6)**	$(469.9)
Change in plan assets						
Fair value of plan assets at beginning of year	**$ 2,356.2**	$ 2,122.6	**N/A**	N/A	**$ 266.6**	$ 222.9
Actual return on plan assets	**225.6**	349.7	**N/A**	N/A	**14.4**	33.0
Employer contribution	**—**	—	**N/A**	N/A	**41.0**	50.6
Benefits paid – excluding lump sum payments	**(122.2)**	(116.1)	**N/A**	N/A	**(43.9)**	(39.9)
Benefits paid – lump sum payments	**(0.2)**	—	**N/A**	N/A	**—**	—
Fair value of plan assets at end of year	**$ 2,459.4**	$ 2,356.2	**N/A**	N/A	**$ 278.1**	$ 266.6
Funded status at December 31st	**$ 202.5**	$ 21.6	**$(32.1)**	$(34.0)	**$(181.5)**	$(203.3)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above at December 31, 2007 and 2006 is as follows:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2007	2006	2007	2006	2007	2006
Prepaid pension	$202.5	$21.6	$ —	$ —	$ —	$ —
Other current liabilities	—	—	(2.4)	(2.0)	—	—
Other deferred credits and other liabilities	—	—	(29.7)	(32.0)	—	—
Accrued postretirement benefits	—	—	—	—	(181.5)	(203.3)

In 2005, as a result of the expected transition of employees into the new 401(k) benefit and the company's corporate reorganization, NU reduced the Pension Plan's obligation via a curtailment benefit related to the reduction in the future years of service expected to be rendered by plan participants. This overall reduction in plan obligation served to reduce the previously unrecognized actuarial losses. In 2006, $41.4 million of this curtailment was reversed because actual levels of elections of the new 401(k) benefit were much lower than expected and is reflected above as an increase to the obligation.

For the Pension Plan, the company amortizes its transition obligation over the remaining service lives of its employees as calculated on an individual subsidiary basis and amortizes the prior service cost and unrecognized net actuarial loss over the remaining service lives of its employees as calculated on an NU consolidated basis. For the PBOP Plan, the company amortizes its transition obligation, prior service cost, and unrecognized net actuarial loss over the remaining service lives of its employees as calculated on an individual operating company basis.

Although the SERP does not have any plan assets, NU supports the SERP with earnings on marketable securities. See Note 10, "Marketable Securities," for further information regarding these investments.

The accumulated benefit obligation for the Pension Plan was $2 billion and $2.1 billion at December 31, 2007 and 2006, respectively, and $30.2 million and $31.4 million for the SERP at December 31, 2007 and 2006, respectively.

The following is a summary of amounts recorded as regulatory assets as a result of SFAS No. 158 at December 31, 2007 and 2006 and the changes in those amounts recorded during the years (millions of dollars):

	At December 31,					
	Pension		SERP		PBOP	
	2007	2006	2007	2006	2007	2006
Transition obligation at beginning of year	$ 0.7	$ —	$ —	$ —	$ 67.9	$ —
Amounts recorded upon adoption of SFAS No. 158	—	0.7	—	—	—	67.9
Amounts reclassified as net periodic benefit expense	(0.2)	—	—	—	(11.3)	—
Transition obligation at end of year	$ 0.5	$ 0.7	$ —	$ —	$ 56.6	$ 67.9
Prior service cost at beginning of year	$ 38.1	$ —	$ 0.6	$ —	$ (3.9)	$ —
Amounts reclassified as net periodic benefit (expense)/income	(8.6)	—	(0.1)	—	0.3	—
Prior service cost arising during the year (1)	37.7	38.1	—	0.6	—	(3.9)
Prior service cost at end of year	$ 67.2	$ 38.1	$ 0.5	$0.6	$ (3.6)	$ (3.9)
Net actuarial losses at beginning of year	$184.7	$ —	$ 5.0	$ —	$114.3	$ —
Amounts reclassified as net periodic benefit expense	(19.9)	—	(0.6)	—	(12.0)	—
Actuarial (gains)/losses arising during the year (1)	(189.0)	184.7	(2.6)	5.0	0.3	114.3
Actuarial (gains)/losses at end of year	$ (24.2)	$184.7	$ 1.8	$5.0	$102.6	$114.3
Total deferred benefit costs as regulatory assets	$ 43.5	$223.5	$ 2.3	$5.6	$155.6	$178.3

(1) Amounts arising for prior service cost and actuarial (gains)/losses in 2006 relate to the nitial adoption of SFAS No. 158.

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2008 are as follows (millions of dollars):

	Estimated Expense in 2008		
	Pension	SERP	PBOP
Transition obligation	$ 0.2	$ —	$11.3
Prior service cost	9.6	0.1	(0.3)
Net actuarial loss	6.3	0.2	10.2
Total	$16.1	$0.3	$21.2

The following is a summary of amounts recorded in accumulated other comprehensive income, as a result of SFAS No. 158 at December 31, 2007 and 2006 and the changes in those amounts recorded during 2007 to other comprehensive income (millions of dollars):

	At December 31,					
	Pension		SERP		PBOP	
	2007	2006	2007	2006	2007	2006
Transition obligation at beginning of year	$ —	$ —	$ —	$ —	$1.5	$ —
Amounts recorded upon adoption of SFAS No. 158	—	—	—	—	—	1.5
Amounts reclassified as net periodic benefit expense	—	—	—	—	(0.3)	—
Transition obligation at end of year	$ —	$ —	$ —	$ —	$1.2	$1.5
Prior service cost at beginning of year	$ 0.6	$ —	$ —	$ —	$ —	$ —
Amounts reclassified as net periodic benefit expense	(0.2)	—	—	—	—	—
Prior service cost arising during the year (1)	2.3	0.6	—	—	—	—
Prior service cost at end of year	$ 2.7	$0.6	$ —	$ —	$ —	$ —
Net actuarial losses at beginning of year	$ 2.6	$ —	$0.3	$ —	$5.5	$ —
Amounts reclassified as net periodic benefit expense	(0.2)	—	—	—	(0.3)	—
Actuarial (gains)/losses arising during the year (1)	(19.8)	2.6	(0.1)	0.3	0.3	5.5
Actuarial (gains)/losses at end of year	$(17.4)	$2.6	$0.2	$0.3	$5.5	$5.5
Total Pension, SERP and PBOP in accumulated other comprehensive income	$(14.7)	$3.2	$0.2	$0.3	$6.7	$7.0

(1) Amounts arising for prior service cost and actuarial (gains)/losses in 2006 relate to the initial adoption of SFAS No. 158.

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2008 are as follows (millions of dollars):

	Estimated Expense in 2008		
	Pension	SERP	PBOP
Transition obligation	$ —	$—	$0.3
Prior service cost	0.3	—	—
Net actuarial (gain)/loss	(0.9)	—	0.2
Total	$(0.6)	$—	$0.5

For further information, see Note 14, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

The following actuarial assumptions were used in calculating the plans' year end funded status:

	At December 31,			
	Pension Benefits and SERP		Postretirement Benefits	
Balance Sheets	2007	2006	2007	2006
Discount rate	6.60%	5.90%	6.35%	5.80%
Compensation/ progression rate	4.00%	4.00%	N/A	N/A
Health care cost trend rate	N/A	N/A	8.50%	9.00%

The components of net periodic benefit expense are as follows:

	For the Years Ended December 31,								
	Pension Benefits			SERP Benefits			Postretirement Benefits		
(Millions of Dollars)	2007	2006	2005	2007	2006	2005	2007	2006	2005
Service cost	$ 47.0	$ 49.4	$ 48.7	$0.8	$1.1	$1.0	$ 7.4	$ 8.3	$ 8.0
Interest cost	136.4	129.7	125.6	1.9	1.9	1.9	25.7	27.3	25.2
Expected return on plan assets	(195.2)	(174.0)	(172.0)	—	—	—	(18.2)	(14.0)	(12.3)
Net transition obligation cost/(asset)	0.2	(0.1)	(0.3)	—	—	—	11.6	11.6	11.8
Prior service cost	8.9	6.6	7.1	0.2	0.2	0.2	(0.3)	(0.3)	(0.4)
Actuarial loss	20.1	41.1	33.4	0.7	0.9	0.6	12.2	17.8	17.5
Net periodic expense – before curtailments and termination (benefits)/expense	17.4	52.7	42.5	3.6	4.1	3.7	38.4	50.7	49.8
Curtailment (benefits)/expense	—	(4.8)	8.9	—	—	—	—	(2.2)	3.7
Termination (benefits)/expense	(0.3)	2.3	2.8	—	—	—	—	0.3	0.5
Total curtailments and termination (benefits)/expense	(0.3)	(2.5)	11.7	—	—	—	—	(1.9)	4.2
Total – net periodic expense	$ 17.1	$ 50.2	$ 54.2	$3.6	$4.1	$3.7	$38.4	$48.8	$54.0

The following assumptions were used to calculate pension and postretirement benefit expense and income amounts:

	For the Years Ended December 31,					
	Pension Benefits and SERP			Postretirement Benefits		
Statements of Income	2007	2006	2005	2007	2006	2005
Discount rate	5.95% (1)	5.80%	6.00%	5.80%	5.65%	5.50%
Expected long-term rate of return	8.75%	8.75%	8.75%	N/A	N/A	N/A
Compensation/progression rate	4.00%	4.00%	4.00%	N/A	N/A	N/A
Expected long-term rate of return –						
Health assets, net of tax	N/A	N/A	N/A	6.85%	6.85%	6.85%
Life assets and non-taxable health assets	N/A	N/A	N/A	8.75%	8.75%	8.75%

(1) The 2007 discount rate for the SERP was 5.9 percent.

The following table represents the PBOP assumed health care cost trend rate for the next year and the assumed ultimate trend rate:

	Year Following December 31,	
	2007	2006
Health care cost trend rate assumed for next year	8.50%	9.00%
Rate to which health care cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2015	2011

At December 31, 2007, the health care cost trend assumption was reset for 2008 at 8.5 percent, decreasing one half percentage point per year to an ultimate rate of 5 percent in 2015.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The effect of changing the assumed health care cost trend rate by one percentage point in each year would have the following effects:

(Millions of Dollars)	One Percentage Point Increase	One Percentage Point Decrease
Effect on total service and interest cost components	$1.0	$ (0.8)
Effect on postretirement benefit obligation	$13.0	$(11.4)

NU's investment strategy for its Pension Plan and PBOP Plan is to maximize the long-term rate of return on those plans' assets within an acceptable level of risk. The investment strategy establishes target allocations, which are routinely reviewed and periodically rebalanced. NU's expected long-term rates of return on Pension Plan assets and PBOP Plan assets are based on these target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension Plan and the PBOP Plan, NU also evaluated input from actuaries and consultants, as well as long-term inflation assumptions and NU's historical 25-year compounded return of approximately 11.8 percent. The Pension Plan's and PBOP Plan's target asset allocation assumptions and expected long-term rate of return assumptions by asset category are as follows:

	At December 31,					
	Pension Benefits				Postretirement Benefits	
	2007		2006		2007 and 2006	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:						
United States	40%	9.25%	45%	9.25%	55%	9.25%
Non-United States	17%	9.25%	14%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	3%	10.25%	2%	10.25%
Private	8%	14.25%	8%	14.25%	—	—
Debt Securities:						
Fixed income	25%	5.50%	20%	5.50%	27%	5.50%
High yield fixed income	—	—	5%	7.50%	5%	7.50%
Real Estate	5%	7.50%	5%	7.50%	—	—

The actual asset allocations at December 31, 2007 and 2006 approximated these target asset allocations. The plans' actual weighted-average asset allocations by asset category are as follows:

	At December 31,			
	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
Equity Securities:				
United States	40%	46%	55%	54%
Non-United States	17%	16%	14%	14%
Emerging markets	5%	4%	1%	1%
Private	7%	5%	—	—
Debt Securities:				
Fixed income	26%	19%	29%	29%
High yield fixed income	—	5%	1%	2%
Real Estate	5%	5%	—	—
Totals	100%	100%	100%	100%

Estimated Future Benefit Payments: The following benefit payments which reflect expected future service, are expected to be paid/(received) for the Pension, SERP and PBOP Plans:

(Millions of Dollars)

Year	Pension Benefits	SERP Benefits	Postretirement Benefits	Government Benefits
2008	$124.1	$ 2.4	$ 44.2	$ (3.7)
2009	128.9	2.3	44.7	(4.0)
2010	132.4	2.5	45.1	(4.3)
2011	136.0	2.6	45.1	(4.7)
2012	140.8	2.7	45.0	(5.1)
2013-2017	805.1	15.3	224.1	(30.4)

The government benefits represent amounts expected to be received from the federal government for the new Medicare prescription drug benefit under the PBOP Plan related to the corresponding year's benefit payments.

Contributions: Currently, NU's policy is to annually fund the Pension Plan in an amount at least equal to that which will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code. NU does not expect to make any contributions to the Pension Plan in 2008. For the PBOP Plan, it is currently NU's policy to annually fund an amount equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits. NU contributed $38 million for the year ended December 31, 2007 to fund the PBOP Plan and expects to make $36.2 million in contributions to the PBOP Plan in 2008. Beginning in 2007, NU made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $3 million in 2007 and is estimated to be $4 million in 2008.

B. Defined Contribution Plans

NU maintains a 401(k) Savings Plan for substantially all NU employees. This savings plan provides for employee contributions up to specified limits. NU matches employee contributions up to a maximum of three percent of eligible compensation with one percent in cash and two percent in NU common shares. The 401(k) matching contributions of cash and NU common shares made by NU were $10.7 million in 2007, $11 million in 2006 and $10.7 million in 2005.

Effective on January 1, 2006, all newly hired, non-bargaining unit employees, and effective on January 1, 2007 or as subject to collective bargaining agreements, certain newly hired bargaining unit employees participate in a new defined contribution savings plan called the K-Vantage benefit. These employees are not eligible to participate in the existing defined benefit Pension Plan. In addition, participants in the Pension Plan at January 1, 2006 were given the opportunity to choose to become a participant in the K-Vantage benefit beginning in 2007, in which case their benefit under the Pension Plan would be frozen. NU makes contributions to the K-Vantage benefit based on a percentage of participants' eligible compensation, as defined by the benefit document. The contributions made by NU were $1.0 million and $0.1 million in 2007 and 2006, respectively.

C. Employee Stock Ownership Plan

NU maintains an Employee Stock Ownership Plan (ESOP) for purposes of allocating shares to employees participating in NU's 401(k) Savings Plan. Under this arrangement, NU issued unsecured notes during 1991 and 1992 totaling $250 million, the proceeds of which were loaned to the ESOP trust (ESOP Notes) for the purchase of 10.8 million newly issued NU common shares (ESOP shares). The ESOP trust is obligated to make principal and interest payments to NU on the ESOP Notes at the same rate that ESOP shares are allocated to employees. NU makes annual contributions to the ESOP trust equal to the ESOP's debt service, less dividends received by the ESOP. NU's contributions to the ESOP trust totaled $4.2 million in 2007, $8.2 million in 2006 and $11.2 million in 2005. Interest expense on the unsecured notes was $3.2 million and $3.3 million in 2006 and 2005, respectively. For the years ended December 31, 2007, 2006 and 2005, NU recognized $6.9 million, $7.4 million and $7.7 million, respectively, of expense related to the ESOP, excluding the interest expense on the unsecured notes. The $75 million Series B note was fully repaid in March of 2005. The $175 million Series A note was fully repaid in December of 2006. As a result, no further interest expense is being incurred for the ESOP.

All dividends received by the ESOP on unallocated shares were used to pay debt service through December 31, 2006. Dividends on the ESOP unallocated shares are not considered dividends for financial reporting purposes. During the first and second quarters of 2006, NU paid a $0.175 per share quarterly dividend. During the third quarter of 2006 through the second quarter of 2007, NU paid a $0.1875 per share quarterly dividend. NU paid a $0.20 per share dividend during the third and fourth quarters of 2007.

In 2007 and 2006, the ESOP trust issued 363,470 and 523,452 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. At December 31, 2007 and 2006, total allocated ESOP shares were 9,660,806 and 9,297,336, respectively, and total unallocated ESOP shares were 1,139,379 and 1,502,849, respectively. The fair market value of the unallocated ESOP shares at December 31, 2007 and 2006 was $35.7 million and $42.3 million, respectively.

D. Share-Based Payments

NU maintains an Employee Share Purchase Plan (ESPP) and other long-term equity-based incentive plans under the Northeast Utilities Incentive Plan (Incentive Plan). In the first quarter of 2006, NU adopted SFAS No. 123(R), "Share-Based Payments," under the modified prospective method. Adoption of SFAS No. 123(R) had an immaterial effect on NU's financial statements and no effect on NU's income/(loss) per share. For the years ended December 31, 2007 and 2006, a tax benefit in excess of compensation cost totaling $3.2 million and $1.1 million, respectively, increased cash flows from financing activities.

SFAS No. 123(R) requires that share-based payments be recorded using the fair value-based method based on the fair value at the date of grant and applies to share-based compensation awards granted on or after January 1, 2006 or to awards for which the requisite service period has not been completed. For prior periods, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," and related guidance, NU used the intrinsic value method and disclosed the pro forma effects as if NU recorded equity-based compensation under the fair value-based method.

Under SFAS No. 123(R), NU accounts for its various share-based plans as follows:

- For grants of restricted shares and restricted share units (RSUs), NU records compensation expense over the vesting period based upon the fair value of NU's common shares at the date of grant but records this expense net of estimated forfeitures.
- Dividend equivalents on RSUs are charged to retained earnings, net of estimated forfeitures.
- NU has not granted any stock options since 2002, and no compensation expense has been recorded. All options were fully vested prior to January 1, 2006.
- For shares sold under the ESPP, an immaterial amount of compensation expense was recorded in the first quarter of 2006, and no compensation expense will be recorded in future periods as a result of a plan amendment that was effective on February 1, 2006.

Incentive Plan: Under the Incentive Plan, NU is authorized to grant up to 4.5 million new shares for various types of awards, including restricted shares, RSUs, performance units and stock options to eligible employees and board members. At December 31, 2007 and 2006, NU had 3,055,083 and 570,494 of common shares, respectively, available for issuance under the Incentive Plan.

Restricted Shares and RSUs: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. NU has granted RSUs under the 2004 through 2007 incentive programs that are subject to three-year and four-year graded vesting schedules. RSUs are paid in shares, including amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of restricted share and RSU transactions for the year ended December 31, 2007 is as follows:

Restricted Shares	Restricted Shares	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	65,674	$15.00			
Granted	—	—			
Vested	(59,424)	$14.14	$0.8		
Outstanding at December 31, 2007	**6,250**	**$18.65**	**$0.1**	**$—**	**0.2**

The per share and total weighted average grant date fair value for restricted shares vested was $14.52 and $1.1 million, respectively, for the year ended December 31, 2006 and $14.60 and $1.4 million, respectively, for the year ended December 31, 2005.

The total compensation cost recognized for restricted shares was $58 thousand, net of taxes of approximately $39 thousand for the year ended December 31, 2007, $0.6 million, net of taxes of approximately $0.4 million for the year ended December 31, 2006, and $0.7 million, net of taxes of approximately $0.4 million for the year ended December 31, 2005.

RSUs	RSUs (Units)	Weighted Average Grant - Date Fair Value	Total Grant - Date Fair Value (Millions)	Remaining Compensation Cost (Millions)	Weighted Average Remaining Period (Years)
Outstanding at December 31, 2006	715,299	$19.41			
Granted	330,785	$28.83	$ 9.5		
Issued	(161,137)	$19.77	$ 3.2		
Forfeited	(53,947)	$20.16	$ 1.1		
Outstanding at December 31, 2007	**831,000**	**$22.99**	**$19.1**	**$7.7**	**1.8**

The per share and total weighted average grant date fair value for RSUs granted was $19.87 and $7.4 million, respectively, for the year ended December 31, 2006 and $18.89 and $5.8 million, respectively, for the year ended December 31, 2005. The weighted average grant date fair value per share for RSUs issued was $18.50 and $19.06 for the years ended December 31, 2006 and 2005, respectively. The total weighted average fair value of RSUs issued was $2.2 million and $1.9 million for the years ended December 31, 2006 and 2005, respectively.

The total compensation cost recognized for RSUs was $3.6 million, net of taxes of approximately $2.4 million for the year ended December 31, 2007, $2.8 million, net of taxes of approximately $1.9 million for the year ended December 31, 2006, and $1.9 million, net of taxes of approximately $1.3 million for the year ended December 31, 2005.

Stock Options: Prior to 2003, NU granted stock options to certain employees. These options were fully vested as of December 31, 2005. The fair value of each stock option grant was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average remaining contractual lives for the options outstanding at December 31, 2007 is 3 years. A summary of stock option transactions is as follows:

		Exercise Price Per Share		
	Options	Range	Weighted Average	Intrinsic Value
				(Millions)
Exercisable - December 31, 2004	1,877,595		$18.7778	
Outstanding - December 31, 2004	1,993,742	$14.9375 - $22.2500	$18.7370	
Exercised	(368,192)		$12.7262	$0.7
Forfeited and cancelled	(503,009)		$18.1703	
Outstanding and Exercisable - December 31, 2005	1,122,541	$14.9375 - $22.2500	$18.4484	
Exercised	(331,943)		$18.3579	$2.0
Forfeited and cancelled	(18,750)		$20.8885	
Outstanding and Exercisable - December 31, 2006	771,848	$14.9375 - $22.2500	$18.4245	
Exercised	(372,168)		$18.5005	$4.8
Forfeited and cancelled	(2,500)		$21.0300	
Outstanding and Exercisable - December 31, 2007	**397,180**	**$14.9375 - $21.0300**	**$18.3369**	**$5.2**

A summary of the ranges of exercise prices of stock options outstanding and exercisable as of December 31, 2007 is as follows:

	Exercise Price Per Share		
Options	Range	Weighted Average	Contractual Term (Years)
76,386	**$14.9375 - $16.6800**	**$15.5435**	**0.8**
320,794	**$16.6900 - $21.0300**	**$19.0021**	**3.6**
397,180	**$14.9375 - $21.0300**	**$18.3369**	**3.0**

Cash received for options exercised during the year ended December 31, 2007 totaled $6.9 million. The tax benefit realized from stock options exercised totaled $1.9 million for the year ended December 31, 2007.

Employee Share Purchase Plan: NU maintains an ESPP for all eligible employees, which allows for NU common shares to be purchased by employees at six-month intervals at 95 percent of the closing market price on the last day of each six-month period. Employees are permitted to purchase shares having a value not exceeding 25 percent of their compensation as of the beginning of the purchase period. The ESPP qualifies as a non-compensatory plan under SFAS No. 123(R), and no compensation expense will be recorded for ESPP purchases.

During 2007 and 2006, employees purchased 26,451 and 113,404 shares, respectively, at discounted prices of $26.27 and $25.97 in 2007 and $16.90 and $21.28 in 2006. At December 31, 2007 and 2006, 1,041,364 shares and 1,067,815 shares remained available for future issuance under the ESPP, respectively.

An income tax rate of 40 percent is used to estimate the tax effect on total share-based payments determined under the fair value-based method for all awards.

E. Other Retirement Benefits

NU provides benefits for retirement and other benefits for certain current and past company officers. The actuarially-determined liability for these benefits, which is included in deferred credits and other liabilities - other on the accompanying consolidated balance sheets, was $46.4 million and $46.5 million at December 31, 2007 and 2006, respectively. During 2007, 2006 and 2005, $8.4 million, $5.6 million and $4.5 million, respectively, was expensed related to these benefits. These benefits are accounted for on an accrual basis and expensed over the service lives of the employees in accordance with the Accounting Principles Board Opinion (APB) No. 12, "Deferred Compensation Contracts."

7. Goodwill and Other Intangible Assets

SFAS No. 142, "Goodwill and Other Intangible Assets," requires that goodwill and intangible assets deemed to have indefinite useful lives be reviewed for impairment at least annually by applying a fair value-based test. NU uses October 1st as the annual goodwill impairment testing date. Goodwill impairment is deemed to exist if the net book value of a reporting unit exceeds its estimated fair value and if the implied fair value of goodwill based on the estimated fair value of the reporting unit is less than the carrying amount.

NU's reporting units are consistent with the operating segments underlying the reportable segments identified in Note 16, "Segment Information," to the consolidated financial statements. The only reporting unit that maintains goodwill is the Yankee Gas reporting unit, which was classified under the regulated companies - gas reportable segment. The goodwill recorded related to the acquisition of Yankee Gas is not being recovered from the customers of Yankee Gas. The goodwill balance held by the Yankee Gas reporting unit at December 31, 2007 and 2006 is $287.6 million.

NU completed its impairment analysis of the Yankee Gas goodwill balance as of October 1, 2007 and determined that no impairment exists. In completing this analysis, the fair value of the reporting unit was estimated using both discounted cash flow methodologies and an analysis of comparable companies and transactions.

As a result of the 2005 decision to exit NU Enterprises, certain goodwill balances and intangible assets were deemed to be impaired. The goodwill balances in these businesses were determined to be impaired in their entirety, and $32.3 million in write-offs were recorded in 2005.

The retail marketing business had an exclusivity agreement with an unamortized balance of $7.2 million and a customer list asset with an unamortized balance of $2 million that were also deemed to be impaired and were written off in 2005. Additionally, the energy services businesses intangible assets not subject to amortization were also impaired, and an $8.5 million pre-tax write-off was recorded in 2005, while an additional pre-tax $0.7 million of other intangible assets were also impaired. The charges related to continuing operations are included in restructuring and impairment charges on the accompanying consolidated statements of income/(loss) and in the NU Enterprises reportable segment in Note 16, "Segment Information," to the consolidated financial statements, with the remainder included in discontinued operations.

8. Commitments and Contingencies

A. Regulatory Developments and Rate Matters

Connecticut:

Procurement Fee Rate Proceedings: CL&P was allowed to collect a fixed procurement fee of 0.50 mills per kilowatt-hour (KWH) from customers that purchased TSO service from 2004 through the end of 2006. One mill is equal to one tenth of a cent. That fee could increase to 0.75 mills per KWH if CL&P outperforms certain regional benchmarks. CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of the procurement fee and requested approval of $5.8 million in incentive fees. On December 8, 2005, a draft decision was issued in this docket, which accepted the methodology as proposed by CL&P and authorized payment of the pre-tax $5.8 million incentive fee. On October 19, 2007, the DPUC released a recommendation prepared by its consultant relative to statistical adjustments to the incentive calculations. The DPUC has set a new schedule allowing for rebuttal of the consultant's report. The new schedule calls for a draft decision in this docket to be issued on March 7, 2008. Management continues to believe that final regulatory approval of the $5.8 million pre-tax amount, which was reflected in 2005 earnings, is probable.

Purchased Gas Adjustment: On September 9, 2005, the DPUC issued a draft decision regarding Yankee Gas's Purchased Gas Adjustment (PGA) clause charges for the period of September 1, 2003 through August 31, 2004. The draft decision disallowed approximately $9 million in previously recovered PGA revenues associated with two separate Yankee Gas unbilled sales and revenue adjustments. At the request of Yankee Gas, the DPUC reopened the PGA hearings on September 20, 2005 and requested that Yankee Gas file supplemental information regarding the two adjustments. Yankee Gas complied with this request. The DPUC issued a new decision on April 20, 2006 requiring an audit of Yankee Gas's previously recovered PGA costs and deferred any conclusion on the $9 million of previously recovered revenues until the completion of the audit. In a subsequent draft decision regarding Yankee Gas PGA charges for the period September 1, 2004 through August 31, 2005, an additional $2 million related to previously recovered revenues was also identified, bringing the total maximum amount at issue with regard to PGA clause charges under audit to approximately $11 million.

The DPUC hired a consulting firm which has concluded an audit of Yankee Gas's previously recovered PGA costs and has submitted its final report. A DPUC hearing was held on October 9, 2007. There is currently no final schedule in this case. Management believes the unbilled sales and revenue adjustments and resulting charges to customers through the PGA clause for both periods were appropriate. Based on the facts of the case, the supplemental information provided to the DPUC and the consultant's final report, management believes the appropriateness of the PGA charges to customers for the time period under review will be approved, and has not reserved for any loss.

Massachusetts:

Transition Cost Reconciliations: WMECO filed its 2005 transition cost reconciliation with the Massachusetts Department of Public Utilities (DPU) on March 31, 2006 and filed its 2006 transition cost reconciliation with the DPU on March 31, 2007. The DPU opened a proceeding for these filings, and evidentiary hearings were held on August 29, 2007. The briefing process was completed during October of 2007. The timing of the decision in this docket is uncertain. Management does not expect the outcome of the DPU's review of these filings to have a material adverse impact on WMECO's net income, financial position or cash flows.

B. Environmental Matters

General: NU is subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. As such, NU has an active environmental auditing and training program and believes that it is substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring.

These estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of NU's responsibility or the extent of remediation required, recently enacted laws and regulations or a change in cost estimates due to certain economic factors.

The amounts recorded as environmental liabilities on the consolidated balance sheets represent management's best estimate of the liability for environmental costs, if reasonably estimable, and take into consideration site assessment and remediation costs. Based on currently available information for estimated site assessment and remediation costs at December 31, 2007 and 2006, NU had $25.8 million and $26.8 million, respectively, recorded as environmental reserves. A reconciliation of the activity in these reserves at December 31, 2007 and 2006 is as follows:

	For the Years Ended December 31,	
(Millions of Dollars)	**2007**	2006
Balance at beginning of year	**$26.8**	$30.7
Additions and adjustments	**1.2**	8.3
Payments and adjustments	**(2.2)**	(12.2)
Balance at end of year	**$25.8**	$26.8

Of the 53 sites NU has currently included in the environmental reserve, 27 sites are in the remediation or long-term monitoring phase, 20 sites have had some level of site assessments completed, and the remaining 6 sites are in the preliminary stages of site assessment.

These liabilities are estimated on an undiscounted basis and do not assume that any amounts are recoverable from insurance companies or other third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2007, in addition to the 53 sites, there were 10 sites for which there are unasserted claims; however, any related site assessment or remediation costs are not probable or estimable at this time. NU's environmental liability also takes into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate previously contaminated sites and any other infrequent and non-recurring clean up costs.

NU remains in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits. HWP is at least partially responsible for this site, and substantial remediation activities at this site have already been conducted. HWP first established a reserve for this site in 1994. Since that time, HWP has recorded charges of approximately $13 million, of which $12.4 million has been spent leaving $0.6 million in the reserve. HWP's reserve is based on its most recent site assessment and estimate of required remediation costs. The ultimate remediation requirements will depend, among other things, on the level and extent of the remaining tar required to be removed, and the extent of HWP's responsibility. These matters are the subject of ongoing discussions with the Massachusetts Department of Environmental Protection and may change from time-to-time. HWP's share of the remediation costs related to this site is not recoverable from ratepayers. At this time, management cannot predict the outcome of this matter or its ultimate effect on NU. Any additional increase to the environmental remediation reserve for this site would be recorded in earnings in future periods when it is probable and reasonably estimable, and potential increases may be material. There were no changes to the environmental reserve for this site in 2007.

MGP Sites: Manufactured gas plant (MGP) sites comprise the largest portion of NU's environmental liability. MGPs are sites that manufactured gas from coal which produced certain byproducts that may pose a risk to human health and the environment. At December 31, 2007 and 2006, $23.6 million and $24.8 million, respectively, represent amounts for the site assessment and remediation of MGPs. At December 31, 2007 and 2006, the five largest MGP sites comprise approximately 68 percent and 65 percent, respectively, of the total MGP environmental liability.

For seven of the 53 sites that are included in the company's liability for environmental costs, the information known and nature of the remediation options at those sites allow for the company to estimate the range of losses for environmental costs. At December 31, 2007, $3.8 million had been accrued as a liability for these sites, which represents management's best estimate of the liability for environmental costs. This amount differs from an estimated range of loss from zero to $18.4 million. For the 46 remaining sites included in the environmental reserve, determining an estimated range of loss is not possible at this time.

CERCLA Matters: The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and its amendments or state equivalents impose joint and several strict liabilities, regardless of fault, upon generators of hazardous substances resulting in removal and remediation costs and environmental damages. Liabilities under these laws can be material and in some instances may be imposed without regard to fault or for past acts that may have been lawful at the time they occurred. Of the 53 sites, five are superfund sites under CERCLA for which NU has been notified that it is a potentially responsible party (PRP) but for which the site assessment and remediation are not being managed by NU. At December 31, 2007, a liability of $0.7 million accrued on these sites represents NU's estimate of its potential remediation costs with respect to these five superfund sites.

It is possible that new information or future developments could require a reassessment of the potential exposure to related environmental matters. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

Environmental Rate Recovery: PSNH and Yankee Gas have rate recovery mechanisms for environmental costs. CL&P recovers a certain level of environmental costs currently in rates but does not have an environmental cost recovery tracking mechanism. Accordingly, changes in CL&P's environmental reserves impact CL&P's earnings. WMECO does not have a separate regulatory mechanism to recover environmental costs from its customers, and changes in WMECO's environmental reserves impact WMECO's earnings. HWP does not have the ability to recover environmental costs in rates, and changes in HWP's environmental reserves impact HWP's earnings.

C. Spent Nuclear Fuel Disposal Costs

Under the Nuclear Waste Policy Act of 1982 (the Act), CL&P and WMECO must pay the United States Department of Energy (DOE) for the costs of disposal of spent nuclear fuel and high-level radioactive waste for the period prior to the sale of their ownership in the Millstone nuclear power stations.

The DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. For nuclear fuel used to generate electricity prior to April 7, 1983 (Prior Period Spent Nuclear Fuel) for CL&P and WMECO, an accrual has been recorded for the full liability, and payment must be made by CL&P and WMECO to the DOE prior to the first delivery of spent fuel to the DOE. After the sale of Millstone, CL&P and WMECO remained responsible for their share of the disposal costs associated with the Prior Period Spent Nuclear Fuel. Until such payment to the DOE is made, the outstanding liability will continue to accrue interest at the 3-month treasury bill yield rate. At December 31, 2007 and 2006, fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel, net of $0.4 million in interest income earned on the WMECO prior spent nuclear fuel trust for the year ended December 31, 2007, are included in long-term debt and were $294.3 million and $280.8 million, respectively, including accumulated interest costs of $212.6 million and $198.7 million, respectively.

During 2004, WMECO established a trust, which holds marketable securities to fund amounts due to the DOE for the disposal of WMECO's Prior Period Spent Nuclear Fuel. For further information on this trust, see Note 10, "Marketable Securities," to the consolidated financial statements.

D. Long-Term Contractual Arrangements

Regulated Companies:

Estimated Future Annual Regulated Companies Costs: The estimated future annual costs of the regulated companies' significant long-term contractual arrangements at December 31, 2007 are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
VYNPC	$ 28.0	$ 30.4	$ 29.2	$ 29.9	$ 7.2	$ —	$ 124.7
Supply/stranded cost contracts	257.1	234.0	212.3	224.0	250.1	1,500.9	2,678.4
Renewable energy contract	—	—	2.5	15.0	15.0	192.4	224.9
Natural gas procurement contracts	54.7	53.9	52.7	51.4	46.0	128.3	387.0
Wood, coal and transportation contracts	132.2	88.7	83.5	73.9	47.4	—	425.7
PNGTS pipeline commitments	2.0	2.0	2.0	2.0	2.0	9.9	19.9
Hydro-Quebec	21.4	21.2	21.1	21.3	21.3	170.5	276.8
Transmission segment project commitments	589.4	52.5	100.7	278.7	264.2	108.6	1,394.1
Yankee Companies billings	34.8	28.6	30.4	26.5	26.6	76.0	222.9
Generation segment project commitments	11.8	9.0	5.0	4.0	2.0	1.0	32.8
Totals	$1,131.4	$520.3	$539.4	$726.7	$681.8	$2,187.6	$5,787.2

VYNPC: CL&P, PSNH and WMECO have commitments to buy approximately 16 percent of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March of 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $25.6 million in 2007, $32.2 million in 2006 and $25.7 million in 2005.

Supply/Stranded Cost Contracts: CL&P, PSNH and WMECO have entered into various IPP contracts that extend through 2024 for the purchase of electricity, including payment obligations resulting from the buydown of electricity purchase contracts. The total cost of purchases and obligations under these contracts amounted to $281.5 million in 2007, $331.9 million in 2006 and $275.3 million in 2005. The majority of the contracts expire by 2014.

In addition, CL&P and UI have entered into four CfDs for a total of approximately 787 MW of capacity with three generation projects to be built or modified and one new demand response project. The CfDs extend through 2026 and obligate the utilities to pay the difference between a set capacity price and the value that the projects receive in the ISO-NE capacity markets. The contracts have terms of up to 15 years beginning in 2009 and are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of these contracts. The amount of CL&P's portion of the costs and benefits of these contracts included in the above table is subject to changes in capacity prices that the projects receive in the ISO-NE capacity markets and will be paid by or refunded to CL&P's customers.

These amounts do not include contractual commitments related to CL&P's standard or TSO service, PSNH's short-term power supply management or WMECO's basic and default service.

Renewable Energy Contract: CL&P has entered into an agreement to purchase energy, capacity and renewable energy credits from a biomass energy plant yet to be built. The contract, beginning in 2010, is an operating lease for a 15-year period with no minimum lease payments. Amounts payable under this contract are subject to a sharing agreement with UI, whereby UI will share 20 percent of the costs and benefits of this contract. CL&P's portion of the costs and benefits of this contract will be paid by or refunded to CL&P's customers.

Natural Gas Procurement Contracts: Yankee Gas has entered into long-term contracts for the purchase of a specified quantity of natural gas in the normal course of business as part of its portfolio of supplies to meet its actual sales commitments. These contracts extend through 2022. The total cost of Yankee Gas's procurement portfolio, including these contracts, amounted to $305.3 million in 2007, $275.1 million in 2006 and $321.2 million in 2005.

Wood, Coal and Transportation Contracts: PSNH has entered into various arrangements for the purchase of wood, coal and the transportation services for fuel supply for its electric generating assets in 2008. PSNH's fuel and natural gas costs, excluding emissions allowances, amounted to approximately $183.8 million in 2007, $149.1 million in 2006 and $193.4 million in 2005.

PNGTS Pipeline Commitments: PSNH has a contract for capacity on the Portland Natural Gas Transmission System (PNGTS) pipeline which extends through 2018. The total cost under this contract amounted to $3.1 million in 2007, $1.4 million in 2006 and $1.6 million in 2005. These costs are not recovered from PSNH's retail customers.

Hydro-Quebec: Along with other New England utilities, CL&P, PSNH and WMECO have entered into agreements to support transmission and terminal facilities which were built to import electricity from the Hydro-Quebec system in Canada. CL&P, PSNH and WMECO are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual O&M expenses and capital costs of those facilities. The total cost of these agreements amounted to $18.8 million in 2007, $20.5 million in 2006 and $21.2 million in 2005.

Transmission Segment Project Commitments: These amounts primarily represent commitments for various services and materials associated with CL&P's Middletown to Norwalk, Glenbrook Cables and Norwalk to Northport-Long Island, New York projects and other projects, including the New England East-West 115 KV and 345 KV Overhead projects. The remaining amounts are for transmission projects at PSNH and WMECO.

Yankee Companies Billings: NU has significant decommissioning and plant closure cost obligations to the Yankee Companies. Each Yankee Company has completed the physical decommissioning of its facility and is now engaged in the long-term storage of its spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including NU's electric utility companies. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The table of estimated future annual regulated companies costs includes the estimated decommissioning and closure costs for CYAPC, MYAPC and YAEC.

See Note 8E, "Commitments and Contingencies – Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

Generation Segment Project Commitments: These amounts represent commitments for engineering and program management services associated with PSNH's coal-fired 440 MW Merrimack Station clean air project, which also includes the addition of a wet scrubber to reduce mercury and sulfur dioxide emissions at Merrimack Station Units 1 and 2. The total cost under these contracts amounted to $1.9 million in 2007 and $0.9 million in 2006.

NU Enterprises:

Estimated Future Annual NU Enterprises Costs: The estimated future annual costs of NU Enterprises' significant contractual arrangements are as follows:

(Millions of Dollars)	2008	2009	2010	2011	2012	Thereafter	Totals
Select Energy purchase agreements	$214.0	$29.7	$32.1	$31.2	$32.3	$32.1	$371.4
Contract assignment agreement	19.1	—	—	—	—	—	19.1
Totals	$233.1	$29.7	$32.1	$31.2	$32.3	$32.1	$390.5

Select Energy Purchase Agreements: Select Energy maintains long-term agreements to purchase energy as part of its portfolio of resources to meet its actual or expected sales commitments. Most purchase commitments are recorded at their mark-to-market value with the exception of one non-derivative contract which is accounted for on the accrual basis.

Contract Assignment Agreement: During the fourth quarter of 2005, Select Energy settled a wholesale contract for $55.9 million with monthly payments that commenced in January of 2006 and end in December of 2008.

Select Energy's purchase commitment amounts are reported on a net basis in fuel, purchased and net interchange power along with certain sales contracts and mark-to-market amounts. Accordingly, the amount included in fuel, purchased and net interchange power will be less than the amounts included in the table above. Select Energy also maintains certain energy commitments whose mark-to-market values have been recorded on the consolidated balance sheets as derivative assets and liabilities. These contracts are included in the table above.

The amount and timing of the costs associated with Select Energy's purchase agreements could be impacted by the exit from the NU Enterprises' businesses.

E. Deferred Contractual Obligations

NU has significant decommissioning and plant closure cost obligations to the Yankee Companies, which have completed the physical decommissioning of all three of their facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies collect decommissioning and closure costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including NU's electric utility companies. These companies recover these costs through state regulatory commission-approved retail rates. A summary of each of NU's subsidiary's ownership percentage in the Yankee Companies at December 31, 2007 is as follows:

	CYAPC	YAEC	MYAPC
CL&P	34.5%	24.5%	12.0%
PSNH	5.0%	7.0%	5.0%
WMECO	9.5%	7.0%	3.0%
Totals	49.0%	38.5%	20.0%

NU's percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages above.

CYAPC: Under the terms of the settlement agreement between CYAPC, the DPUC, the Connecticut Office of Consumer Counsel, and Maine regulators, the parties agreed to a revised decommissioning estimate of $642.9 million (in 2006 dollars). Annual collections began in January of 2007, and were reduced from the $93 million originally requested for years 2007 through 2010 to lower levels ranging from $37 million in 2007 rising to $46 million in 2015. The reduction to annual collections was achieved by extending the collection period by 5 years through 2015 by reflecting the proceeds from a settlement agreement with Bechtel Power Corporation, by reducing collections in 2007, 2008 and 2009 by $5 million per year, and making other adjustments. NU believes CL&P and WMECO will recover their shares of this obligation from their customers. PSNH has recovered its share of these costs from its customers.

YAEC: On July 31, 2006, the FERC approved a settlement agreement with the DPUC, the Massachusetts Attorney General and the Vermont Department of Public Service previously filed by YAEC. This settlement agreement did not materially affect the level of 2006 charges. Under the settlement agreement, YAEC agreed to reduce its November 2005 decommissioning cost increase from $85 million to $79 million. Other terms of the settlement agreement include extending the collection period for charges through December 2014, reconciling and adjusting future charges based on actual decontamination and decommissioning expenses and the decommissioning trust fund's actual investment earnings. NU believes that its $24.9 million share of the increase in decommissioning costs will ultimately be recovered from the customers of CL&P and WMECO (approximately $19.4 million and $5.5 million for CL&P and WMECO, respectively). PSNH has recovered its share of these costs from its customers.

MYAPC: MYAPC is collecting revenues from CL&P, PSNH, WMECO and other owners that are adequate to recover the remaining cost of decommissioning its plant, and CL&P and WMECO expect to recover their respective shares of such costs through future rates. PSNH has recovered its share of these costs from its customers.

Spent Nuclear Fuel Litigation: In 1998, CYAPC, YAEC and MYAPC filed separate complaints against the United States Department of Energy (DOE) in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal by January 31, 1998 pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. In a ruling released on October 4, 2006, the Court of Federal Claims held that the DOE was liable for damages to CYAPC for $34.2 million through 2001, YAEC for $32.9 million through 2001 and MYAPC for $75.8 million through 2002. The Yankee Companies had claimed actual damages for the same periods as follows: CYAPC: $37.7 million; YAEC: $60.8 million; and MYAPC: $78.1 million. Most of the reduction in the claimed actual damages related to disallowed spent nuclear fuel pool operating expenses.

The Court of Federal Claims, following precedent set in another case, did not award the Yankee Companies future damages covering the period beyond the 2001/2002 damages award dates. In December of 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December of 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The refund to CL&P, PSNH and WMECO of any damages that may be recovered from the DOE will be realized through the Yankee Companies' FERC-approved rate settlement agreements, subject to final determination of the FERC. The appeal is expected to be argued in 2008 with a decision from the Court of Appeals to follow.

CL&P, PSNH and WMECO's aggregate share of these damages is $44.7 million. Their respective shares of these damages are as follows: CL&P: $29 million; PSNH: $7.8 million; and WMECO: $7.9 million. CL&P, PSNH and WMECO cannot at this time determine the timing or amount of any ultimate recovery from the DOE, through the Yankee Companies, on this matter. However, NU does believe that any net settlement proceeds it receives would be incorporated into FERC-approved recoveries, which would be passed on to its customers, through reduced charges.

F. NRG Energy, Inc. Exposures

Certain subsidiaries of NU, including CL&P and Yankee Gas, entered into transactions with NRG and certain of its subsidiaries. On May 14, 2003, NRG and certain subsidiaries of NRG filed voluntary bankruptcy petitions, and on December 5, 2003, NRG emerged from bankruptcy. NU's NRG-related exposures as a result of these transactions relate to 1) the refunding of approximately $28 million of congestion charges previously withheld from NRG prior to the implementation of standard market design (SMD) on March 1, 2003, 2) the recovery of approximately $30.2 million of CL&P's station service billings from NRG, which is currently the subject of an arbitration, and 3) the recovery of, among other claimed damages, approximately $17.5 million of capital costs and expenses incurred by Yankee Gas related to an NRG subsidiary's generating plant construction project that has ceased.

On July 20, 2007, the United States District Court for the District of Connecticut issued a ruling granting CL&P's motion for summary judgment against NRG in the pre-SMD congestion litigation. In this decision, the court held that NRG was contractually obligated to pay for congestion charges imposed during the term of the October 29, 1999 standard offer service wholesale sales agreement between CL&P and NRG and found in favor of CL&P and against NRG on each of NRG's four counterclaims. NRG did not appeal the judgment and the matter is closed.

On January 8, 2008, CL&P and NRG filed a proposed confidential settlement with the DPUC, which would settle the pending dispute concerning the scope of NRG's responsibility to pay for certain delivery service charges to CL&P, as well as the claim for recovery of costs related to the ceased generating plant project. On January 28, 2008, the DPUC issued a final decision in CL&P's rate case proceeding in which it also approved the settlement between CL&P and NRG. The payment that CL&P will receive from NRG under the settlement and the rate relief approved in the January 28, 2008 DPUC decision essentially reimburses CL&P for its net station service and generating plant construction costs receivables from NRG. This settlement was signed by NRG, CL&P and Yankee Gas in February of 2008, which brought a conclusion to all outstanding matters mentioned above. The settlement did not and will not have an adverse effect on NU's consolidated net income, financial position or cash flows for the years ended December 31, 2007 and 2008, respectively.

G. Consolidated Edison, Inc. Merger Litigation

Certain gain and loss contingencies exist with regard to the merger agreement between NU and Consolidated Edison, Inc. (Con Edison) and the related litigation.

In 2001, Con Edison advised NU that it was unwilling to close its merger with NU on the terms set forth in the 1999 merger agreement (Merger Agreement). In March of 2001, NU filed suit against Con Edison seeking damages in excess of $1 billion.

In a 2005 opinion, a panel of three judges at the Second Circuit held that NU shareholders had no right to sue Con Edison for its alleged breach of the parties' Merger Agreement. This ruling left intact the remaining claims between NU and Con Edison for breach of contract, which include NU's claim for recovery of costs and expenses of approximately $32 million and Con Edison's claim for damages of at least $314 million. Any damage award would include pre-judgment interest from the date of the filing of the claim. NU's request for a rehearing was denied in 2006. NU opted not to seek review of this ruling by the United States Supreme Court. In April of 2006, NU filed its motion for partial summary judgment on Con Edison's damage claim. On January 31, 2008, the trial judge denied a series of motions by both NU and Con Edison that had been pending for more than one year, including NU's motion for an order dismissing Con Edison's synergy damage claim. The judge ordered the parties to be trial ready on four days' notice beginning March 21, 2008. It is not possible for NU to predict either the outcome of this matter or its ultimate effect on NU.

H. Guarantees and Indemnifications

NU provides credit assurances on behalf of subsidiaries in the form of guarantees and letters of credit (LOCs) in the normal course of business. NU has also provided guarantees and various indemnifications on behalf of external parties as a result of the sales of SESI, the retail marketing business and the competitive generation business. The following table summarizes NU's maximum exposure at December 31, 2007, in accordance with FIN 45, "Guarantor's Accounting and

Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," expiration dates, and fair value of amounts recorded.

Company	Description	Maximum Exposure (in millions)	Expiration Date(s)	Fair Value of Amounts Recorded (in millions)
On behalf of external parties:				
SESI	General indemnifications in connection with the sale of SESI including completeness and accuracy of information provided, compliance with laws, and various claims	Not Specified (1)	None	$—
	Specific indemnifications in connection with the sale of SESI for estimated costs to complete or modify specific projects	Not Specified (1)	Through project completion	$0.2
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts	$2.0	2017-2018	$0.1
	Surety bonds covering certain projects	$77.2	Through project completion (2)	$—
Hess (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, validity of contract information, completeness and accuracy of information provided, absence of default on contracts, and various claims	Not Specified (1)	None	$—
ECP (Competitive Generation Business)	General indemnifications in connection with the sale of NGC and the generating assets of Mt. Tom including compliance with laws, validity of contract information, completeness and accuracy of information provided, absence of default on contracts, and various claims	Not Specified (1)	None	$—
On behalf of subsidiaries:				
Regulated Companies	Surety bonds, primarily for self-insurance	$15.3	None	N/A
	Letters of credit	$25.0	2008	N/A
Rocky River Realty Company	Lease payments for real estate	$11.2	2024	N/A
NUSCO	Lease payments for fleet of vehicles	$9.1	None	N/A
Boulos	Surety bonds covering ongoing projects	$66.2	Through project completion	N/A
SECI	Surety bonds covering projects	$8.7	N/A (6)	N/A
NGS	Performance guarantee and insurance bonds	$23.9 (3)	2020 (3)	N/A
Select Energy	Performance guarantees and surety bonds for retail marketing contracts	$5.3 (4)	None (5)	N/A
	Performance guarantees for wholesale contracts	$97.4 (4)	2013	N/A
	Letters of credit	$2.0	2009	N/A

(1) There is no specified maximum exposure included in the related sale agreements. For retail marketing business guarantees, all claims are subject to a $0.3 million threshold.

(2) The company expects appropriate acknowledgment of project completion for the majority of these surety bonds by the end of the second quarter of 2008.

(3) Included in the maximum exposure is $22.7 million related to a performance guarantee of NGS's obligations for which there is no specified maximum exposure in the agreement. The maximum exposure is calculated as of December 31, 2007 based on limits of NGS's liability contained in the underlying service contract and assumes that NGS will perform under that contract through its expiration in 2020. The remaining $1.2 million of maximum exposure relates to insurance bonds with no expiration date which are billed annually on their anniversary date.

(4) Maximum exposure is as of December 31, 2007; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

(5) NU does not currently anticipate that these remaining guarantees on behalf of Select Energy will result in significant guarantees of the performance of Hess.

(6) The company expects appropriate acknowledgment of project completion for these surety bonds in 2008.

Many of the underlying contracts that NU guarantees, as well as certain surety bonds, contain credit ratings triggers that would require NU to post collateral in the event that NU's credit ratings are downgraded below investment grade.

In July of 2006, under its former SESI guarantee, NU was required to purchase contract payments relating to the only guaranteed SESI project that was financed and behind schedule. NU recorded $0.5 million and $1.1 million in losses in 2007 and 2006, respectively, to reduce the carrying value of the contract payments purchased to the amount expected to be received from refinancing through SESI's completion of the project. The carrying value of these assets is $8.8 million at December 31, 2007 and is included in other deferred debits on the accompanying consolidated balance sheets. NU may record additional losses associated with this transaction, the amount of which will depend on changes in interest rates used to determine SESI's refinancing proceeds, the amount of project cash available to offset NU's costs, and other factors.

I. Transmission Rate Matters and FERC Regulatory Issues

As a result of an order issued by the FERC on October 31, 2006 relating to incentives on new transmission facilities in New England (FERC ROE decision), NU recorded an estimated regulatory liability for refunds of $25.6 million as of December 31, 2006. In 2007, NU completed the customer refunds that were calculated in accordance with the compliance filing required by the FERC ROE decision, and refunded approximately $23.9 million to regional, local and localized transmission customers. The $1.7 million positive pre-tax difference ($1 million after-tax) between the estimated regulatory liability recorded and the actual amount refunded was recognized in earnings in 2007.

Pursuant to the October 31, 2006 FERC ROE decision, the New England transmission owners submitted a compliance filing that calculated the refund amounts for transmission customers for the February 1, 2005 to October 31, 2006 time period. Subsequently, on July 26, 2007, the FERC disagreed with the ROEs the transmission owners used in their refund calculations for the 15-month period between June 3, 2005 and September 3, 2006, rejected a portion of the compliance filing, and required another compliance filing within 30 days. On August 27, 2007, NU and the other New England transmission owners submitted a revised compliance filing, which outlined the regional refund process to comply with the FERC's July 26, 2007 order. In addition, the transmission owners filed a request for rehearing claiming that the FERC improperly set the floor for refunds based on the lower rates that the FERC approved in its October 31, 2006 order, rather than the last approved rates, for the period from June 3, 2005 to September 3, 2006. The FERC denied this request on January 17, 2008, and the transmission owners have until March 17, 2008 to appeal, if they so choose.

NU's transmission companies refunded approximately $2.2 million of revenues and interest related to the July 26, 2007 order (approximately $1.4 million after-tax). NU's distribution companies received a net after-tax benefit of approximately $0.3 million as a result of these refunds. The refunds and benefits totaling $1.1 million after-tax were recorded in 2007.

J. Other Litigation and Legal Proceedings

NU and its subsidiaries are involved in other legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, some of which involve management's best estimate of probable loss as defined by SFAS No. 5. The company records and discloses losses when these losses are probable and reasonably estimable in accordance with SFAS No. 5, discloses matters when losses are probable but not estimable, and expenses legal costs related to the defense of loss contingencies as incurred.

9. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Cash and Cash Equivalents and Special Deposits: The carrying amounts approximate fair value due to the short-term nature of these cash items.

SERP and Non-SERP Investments: Investments held for the benefit of the SERP and non-SERP are recorded at fair market value based upon quoted market prices. The investments having a cost basis of $63.7 million and $59.7 million as of December 31, 2007 and 2006, respectively, held for benefit of the SERP and non-SERP were recorded at their fair market values of $68.4 million and $65 million at December 31, 2007 and 2006, respectively. For further information regarding the SERP liabilities and related investments, see Note 6A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions," and Note 10, "Marketable Securities," to the consolidated financial statements.

Prior Spent Nuclear Fuel Trust: During 2004, WMECO established a trust to fund the amounts due to the DOE for its prior spent nuclear fuel obligation. These investments having a cost basis of $55.6 million and $53.4 million for 2007 and 2006, respectively, were recorded at their fair market value of $55.7 million and $53.4 million at December 31, 2007 and 2006, respectively. For further information regarding these investments, see Note 10, "Marketable Securities," to the consolidated financial statements.

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of NU's fixed-rate securities is based upon quoted market prices for those issues or similar issues. Adjustable rate securities are assumed to have a fair value equal to their carrying value. The carrying amounts of NU's financial instruments and the estimated fair values are as follows:

(Millions of Dollars)	At December 31, 2007 Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 88.2
Long-term debt –		
First mortgage bonds	1,806.3	1,792.4
Other long-term debt	1,832.3	1,867.4
Rate reduction bonds	917.4	975.2

(Millions of Dollars)	At December 31, 2006 Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 92.4
Long-term debt –		
First mortgage bonds	1,240.6	1,268.8
Other long-term debt	1,734.4	1,775.9
Rate reduction bonds	1,177.2	1,235.4

Other long-term debt includes $294.3 million and $280.8 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2007 and 2006, respectively.

Other Financial Instruments: The carrying value of other financial instruments included in current assets and current liabilities, including investments in securitizable assets, approximates their fair value due to the short-term nature of these instruments.

10. Marketable Securities

The following is a summary of NU's available-for-sale securities related to NU's SERP and non-SERP assets and WMECO's prior spent nuclear fuel trust assets, which are recorded at their fair values and are included in current and long-term marketable securities on the accompanying consolidated balance sheets.

(Millions of Dollars)	At December 31, 2007	2006
SERP and non-SERP securities	$ 68.4	$ 65.0
WMECO prior spent nuclear fuel trust	55.7	53.4
Totals	$124.1	$118.4

At December 31, 2007 and 2006, marketable securities are comprised of the following:

(Millions of Dollars)	Amortized Cost	At December 31, 2007 Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$ 23.5	$4.3	$—	$ 27.8
Non-United States equity securities	8.3	—	—	8.3
Fixed income securities	87.5	0.5	—	88.0
Totals	$119.3	$4.8	$—	$124.1

(Millions of Dollars)	Amortized Cost	At December 31, 2006 Pre-Tax Gross Unrealized Gains	Pre-Tax Gross Unrealized Losses	Estimated Fair Value
United States equity securities	$ 21.2	$5.0	$(0.3)	$ 25.9
Non-United States equity securities	7.2	0.7	—	7.9
Fixed income securities	84.7	0.4	(0.5)	84.6
Totals	$113.1	$6.1	$(0.8)	$118.4

For the year ended December 31, 2007, NU recorded a $1.9 million pre-tax charge related to the unrealized losses on securities in the SERP portfolio, and a $0.6 million offset to the spent nuclear fuel obligation in long-term debt related to the unrealized losses on securities in the WMECO spent nuclear fuel trust. For the year ended December 31, 2006, unrealized losses of $0.8 million were recorded on these securities, of which $0.2 million of this amount reflected loss positions greater than twelve months.

For information related to the change in net unrealized holding gains and losses included in accumulated other comprehensive income, see Note 14, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

For the years ended December 31, 2007, 2006 and 2005, realized gains and losses recognized on the sale of available-for-sale securities are as follows:

(Millions of Dollars)	Realized Gains	Realized Losses	Net Realized Gains/(Losses)
2007	**$2.8**	**$(1.0)**	**$1.8**
2006	5.2	(1.3)	3.9
2005	1.3	(7.1)	(5.8)

For the years ended December 31, 2007, 2006 and 2005, net realized losses of $40 thousand, $0.3 million and $0.4 million, respectively, were recorded relating to the WMECO spent nuclear fuel trust. For the years ended December 31, 2007, 2006 and 2005, all other net realized gains/(losses) totaled $1.9 million, $4.2 million and $(5.4) million, respectively, and are included in other income, net on the accompanying consolidated statements of income/(loss). Included in the realized gains/(losses) is a pre-tax gain of $3.1 million and a pre-tax loss of $6.1 million for the years ended December 31, 2006 and 2005, respectively, related to NU's investment in Globix, which was sold on April 6, 2006.

NU utilizes the specific identification basis method for SERP and non-SERP securities and the average cost basis method for the WMECO prior spent nuclear fuel trust to compute the realized gains and losses on the sale of available-for-sale securities.

Proceeds from the sale of these securities, including proceeds from short-term investments, totaled $254.8 million, $193.5 million and $137.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

At December 31, 2007, the contractual maturities of the available-for-sale securities are as follows:

(Millions of Dollars)	Amortized Cost	Estimated Fair Value
Less than one year	$ 34.5	$ 34.7
One to five years	27.1	27.2
Six to ten years	6.7	6.8
Greater than ten years	19.1	19.3
Subtotal	87.4	88.0
Equity securities	31.9	36.1
Total	$119.3	$124.1

For further information regarding marketable securities, see Note 1T, "Summary of Significant Accounting Policies – Marketable Securities," to the consolidated financial statements.

11. Leases

Various NU subsidiaries have entered into lease agreements, some of which are capital leases, for the use of data processing and office equipment, vehicles, and office space. The provisions of these lease agreements generally contain renewal options. Certain lease agreements contain contingent lease payments. The contingent lease payments are based on various factors, such as the commercial paper rate plus a credit spread or the consumer price index.

Capital lease rental payments were $2.9 million in 2007, $3.3 million in 2006 and $3.4 million in 2005. Interest included in capital lease rental payments was $2 million in 2007, and $1.9 million in both 2006 and 2005. Capital lease asset amortization was $0.9 million in 2007, $0.9 million in 2006 and $0.8 million in 2005.

Operating lease rental payments charged to expense were $19.6 million in 2007, $10.9 million in 2006 and $15.6 million in 2005. These amounts include $0.7 million and $1.1 million included in income from discontinued operations on the accompanying consolidated statements of income/(loss) for the years ended December 31, 2006 and 2005, respectively. The capitalized portion of operating lease payments was approximately $10.5 million, $10 million and $9.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Future minimum rental payments excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term noncancelable leases, at December 31, 2007 are as follows:

(Millions of Dollars)	Capital Leases	Operating Leases
2008	$ 3.5	$ 30.5
2009	3.6	27.5
2010	1.8	24.1
2011	1.9	19.1
2012	2.0	14.5
Thereafter	17.4	47.3
Future minimum lease payments	$30.2	$163.0
Less amount representing interest	(15.5)	
Present value of future minimum lease payments	$14.7	

In 2007, NU entered into certain contracts for the purchase of energy that qualify as leases under Emerging Issues Task Force (EITF) No. 01-8, "Determining Whether an Arrangement Contains a Lease." These contracts do not have minimum lease payments and therefore are not included in the table above. See Note 8D, "Commitments and Contingencies – Long-Term Contractual Arrangements," for further information regarding these contracts.

12. Long-Term Debt

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2007, for the years 2008 through 2012 and thereafter, which include fees and interest due for spent nuclear fuel disposal costs, net unamortized premiums or discounts and other fair value adjustments at December 31, 2007, are as follows (millions of dollars):

Year	
2008	$ 154.3
2009	99.3
2010	4.3
2011	4.3
2012	267.3
Thereafter	2,814.8
Fees and interest due for spent nuclear fuel disposal costs	294.3
Net unamortized premiums and discounts and other fair value adjustments	(0.7)
Total	$3,637.9

Essentially all utility plant of CL&P, PSNH and Yankee Gas is subject to the liens of each company's respective first mortgage bond indenture.

CL&P has $315.5 million of tax-exempt Pollution Control Revenue Bonds (PCRBs) secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indentures.

PSNH has $89.3 million of MBIA-insured tax-exempt PCRBs that are remarketed in an auction rate mode every 35 days. In addition, CL&P has $62 million of tax-exempt PCRBs secured by bond insurance and first mortgage bonds. For financial reporting purposes, this debt is not considered to be first mortgage bonds unless CL&P fails to meet its obligations under the PCRBs.

PSNH entered into financing arrangements with the Business Finance Authority (BFA) of the state of New Hampshire, pursuant to which the BFA issued five series of PCRBs and loaned the proceeds to PSNH. At both December 31, 2007 and 2006, $407.3 million of the PCRBs were outstanding. PSNH's obligation to repay each series of PCRBs is secured by first mortgage bonds and bond insurance as it applies to the 2001 Series A, B and C. Each such series of first mortgage bonds contains similar terms and provisions as the applicable series of PCRBs. For financial reporting purposes, these first mortgage bonds would not be considered outstanding unless PSNH failed to meet its obligations under the PCRBs.

NU's long-term debt agreements provide that certain of its subsidiaries must comply with certain financial and non-financial covenants as are customarily included in such agreements, including but not limited to, debt service coverage ratios and interest coverage ratios. The parties to these agreements currently are and expect to remain in compliance with these covenants.

The weighted average effective interest rate on PSNH's Series A variable-rate pollution control notes was 3.87 percent for 2007 and 3.50 percent for 2006. The CL&P pollution control note due in 2031 has an interest rate of 3.35 percent effective through October 1, 2008, at which time the bonds will be remarketed and the interest rate will be adjusted.

Long-term debt – First Mortgage Bonds on the accompanying consolidated statements of capitalization at December 31, 2007 includes the issuance of $500 million and $70 million at CL&P and PSNH, respectively.

Other long-term debt – other on the accompanying consolidated statements of capitalization at December 31, 2007 includes a senior unsecured note issuance of $40 million at WMECO and an unsecured floating rate long-term debt issuance of $45 million at Yankee Gas.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 8C, "Commitments and Contingencies – Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

The change in fair value totaling a positive $4.2 million and a negative $6.5 million at December 31, 2007 and 2006, respectively, on the accompanying consolidated statements of capitalization, reflects the NU parent 7.25 percent amortizing note, due 2012 in the amount of $263 million that is hedged with a fixed to floating interest rate swap. The change in fair value of the interest component of the debt was recorded as an adjustment to long-term debt with an equal and offsetting adjustment to derivative assets and liabilities for the change in fair value of the fixed to floating interest rate swap.

13. Dividend Restrictions

NU's ability to pay dividends is not regulated under the Federal Power Act, but may be affected by certain state statutes, the leverage restriction tied to its ratio of consolidated total debt to total capitalization in its revolving credit agreement and the ability of NU's subsidiaries to pay dividends to it. The Federal Power Act limits the payment of dividends by CL&P, PSNH and WMECO to their retained earnings balances, and PSNH is required to reserve an additional amount under its FERC hydroelectric license conditions. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. CL&P, PSNH, WMECO and Yankee Gas also have a revolving credit agreement that imposes leverage restrictions, also including but not limited to their ratios of consolidated total debt to total capitalization. The $947 million retained earnings balance is subject to these leverage restrictions. Approximately $11 million of PSNH's retained earnings is subject to restriction under its FERC hydroelectric license conditions.

14. Accumulated Other Comprehensive Income/(Loss)

The accumulated balance for each other comprehensive income/(loss), net of tax, item is as follows:

(Millions of Dollars)	December 31, 2006	Current Period Change	December 31, **2007**
Qualified cash flow hedging instruments	$5.9	$(3.6)	**$2.3**
Unrealized gains on securities	3.0	(0.1)	**2.9**
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	(4.4)	8.6	**4.2**
Accumulated other comprehensive income	$4.5	$ 4.9	**$9.4**

(Millions of Dollars)	December 31, 2005	Current Period Change	December 31, 2006
Qualified cash flow hedging instruments	$18.2	$(12.3)	$5.9
Unrealized gains on securities	2.3	0.7	3.0
Minimum SERP liability (1)	(0.5)	0.5	—
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	—	(4.4)	(4.4)
Accumulated other comprehensive income/(loss)	$20.0	$(15.5)	$4.5

(1) The 2006 change of $0.5 million related to the minimum SERP liability includes $0.3 million to reduce the additional minimum SERP liability before the adoption of SFAS No. 158 and $0.2 million to reverse the remaining balance as part of the adoption of SFAS No. 158. See Note 6A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pensions," for additional information regarding the adoption of SFAS No. 158.

The changes in the components of other comprehensive income/(loss) are reported net of the following income tax effects:

(Millions of Dollars)	**2007**	2006	2005
Qualified cash flow hedging instruments	**$ 2.5**	$ 6.9	$(13.4)
Unrealized gains on securities	**0.1**	(0.5)	0.6
Minimum SERP liability	**—**	(0.3)	(0.3)
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	**(9.8)**	6.1	—
Accumulated other comprehensive income/(loss)	**$(7.2)**	$12.2	$(13.1)

Fair value adjustments included in accumulated other comprehensive income/(loss) for NU's qualified cash flow hedging instruments are as follows:

(Millions of Dollars, Net of Tax)	At December 31, 2007	2006
Balance at beginning of year	**$5.9**	$18.2
Hedged transactions recognized into earnings	**0.2**	2.3
Amount reclassified into earnings due to the discontinuation of cash flow hedges	**—**	(14.1)
Change in fair value of hedged transactions delivered	—	(4.5)
Cash flow transactions entered into for period	**(3.8)**	4.0
Net change associated with hedging transactions	**(3.6)**	(12.3)
Total fair value adjustments included in accumulated other comprehensive income	**$2.3**	$ 5.9

For the years ended December 31, 2007 and 2006, $0.2 million and $2.3 million, respectively, net of tax, was reclassified from accumulated other comprehensive income into earnings in connection with the consummation of interest rate swap agreements and the amortization of existing interest rate hedges.

In December of 2007, NU parent, CL&P, PSNH and Yankee Gas each entered into a forward interest rate swap agreement associated with their respective planned 2008 long-term debt issuances. As a result, $3.1 million, net of tax, was recorded in accumulated other comprehensive income with a corresponding pre-tax offset to derivative assets for the fair value of the derivative instruments as of December 31, 2007. For further information, see Note 5, "Derivative Instruments," to the consolidated financial statements.

In July of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest rates associated with $50 million of its $100 million, 10-year fixed rate long-term debt issuance and with $50 million of its $100 million, 30-year fixed rate long-term debt issuance. Under the agreements, CL&P had a LIBOR swap rate of 5.718 percent for the 10-year hedge and 5.865 percent for the 30-year hedge, both based on the notional amounts of $50 million in long-term debt that was issued in July of 2007. On July 16, 2007, the hedge was settled and a net-of-tax charge of $4.7 million ($7.7 million pre-tax) was recorded in accumulated other comprehensive income to be amortized into earnings over the terms of the long-term debt. In addition, a net of tax charge of $67 thousand ($110 thousand pre-tax) was recorded related to ineffectiveness incurred upon termination of the hedge.

Also, in July of 2007, WMECO entered into a forward interest rate swap agreement to hedge the interest rate associated with its $40 million, 30-year fixed rate long-term debt issuance. Under the agreement, WMECO had a LIBOR swap rate of 5.882 percent based on the notional amount of $40 million in long-term debt that was issued in July of 2007. On August 15, 2007, the hedge was settled and a net of tax charge of $0.6 million ($1 million pre-tax) was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

In February of 2007, CL&P entered into two forward interest rate swap agreements to hedge the interest rates associated with $75 million of its $150 million, 10-year fixed rate long-term debt issuance and with $75 million of its $150 million, 30-year fixed rate long-term debt issuance. Under the agreements, CL&P had a LIBOR swap rate of 5.229 percent for the 10-year hedge and 5.369 percent for the 30-year hedge, both based on the notional amounts of $75 million in long-term debt that was issued in March of 2007. On March 27, 2007, the hedge was settled and a net of tax charge of $1.6 million ($2.6 million pre-tax) was recorded in accumulated other comprehensive income to be amortized into earnings over the terms of the long-term debt.

In March of 2006, CL&P entered into a forward interest rate swap agreement to hedge the interest rate associated with $125 million of its planned $250 million, 30-year fixed rate long-term debt issuance. Under the agreement, CL&P had a LIBOR swap rate of 5.322 percent based on the notional amount of $125 million in long-term debt that was issued in June of 2006. On June 1, 2006, the hedged transaction was settled, and as a result $4.6 million, net of tax ($7.8 million pre-tax), was recorded in accumulated other comprehensive income to be amortized into earnings over the term of the long-term debt.

In the first quarter of 2006, $14.1 million was reclassified from accumulated other comprehensive income into earnings (and included in other operation expenses) due to discontinuing cash flow hedge accounting and the conclusion that the retail marketing contracts hedged beyond June 1, 2006 were no longer probable of physical delivery due to the retail business being sold.

It is estimated that a charge of $0.3 million will be reclassified from accumulated other comprehensive income as a decrease to earnings over the next 12 months as a result of amortization of the interest rate swap agreements which have been settled. This amount will be impacted by the settlement of forward interest rate swap agreements. At December 31, 2007, it is estimated that a pre-tax $0.1 million included in the accumulated other comprehensive income balance will be reclassified as an increase to earnings over the next 12 months related to Pension, SERP and other postretirement benefits adjustments.

15. Earnings Per Share

Earnings per share (EPS) is computed based upon the weighted average number of common shares outstanding, excluding unallocated ESOP shares, during each year. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect if certain securities are converted into common stock. In 2006 and 2005, 2,500 options and 1,122,541 options, respectively, were excluded from the following table as these options were antidilutive. In 2007, there were no antidilutive options outstanding. The following table sets forth the components of basic and diluted EPS:

(Millions of Dollars, except share information)	2007	2006	2005
Income/(loss) from continuing operations	**$245.9**	$132.9	$(256.9)
Income from discontinued operations	**0.6**	337.7	4.4
Income/(loss) before cumulative effect of accounting change	**246.5**	470.6	(252.5)
Cumulative effect of accounting change, net of tax benefit	**—**	—	(1.0)
Net income/(loss)	**$246.5**	$470.6	$(253.5)
Basic common shares outstanding (average)	**154,759,727**	153,767,527	131,638,953
Dilutive effect	**544,634**	379,142	N/A
Fully diluted common shares outstanding (average)	**155,304,361**	154,146,669	131,638,953
Basic EPS:			
Income/(loss) from continuing operations	**$ 1.59**	$ 0.86	$ (1.95)
Income from discontinued operations	**—**	2.20	0.03
Cumulative effect of accounting change, net of tax benefit	**—**	—	(0.01)
Net income/(loss)	**$ 1.59**	$ 3.06	$ (1.93)
Fully Diluted EPS:			
Income/(loss) from continuing operations	**$ 1.59**	$ 0.86	$ (1.95)
Income from discontinued operations	**—**	2.19	0.03
Cumulative effect of accounting change, net of tax benefit	**—**	—	(0.01)
Net income/(loss)	**$ 1.59**	$ 3.05	$ (1.93)

RSUs are included in basic common shares outstanding when shares are both vested and issued. The dilutive effect of RSUs granted but not issued is calculated using the treasury stock method. Assumed proceeds of RSUs under the treasury stock method consist of the remaining compensation cost to be recognized and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the RSUs (the difference between the market value of RSUs using the average market price during the year and the grant date market value).

The dilutive effect of stock options is also calculated using the treasury stock method. Assumed proceeds for stock options consist of remaining compensation cost to be recognized, cash proceeds that would be received upon exercise, and a theoretical tax benefit. The theoretical tax benefit is calculated as the tax impact of the intrinsic value of the stock options (the difference between the market value of the average stock options outstanding for the year using the average market price and the grant price).

Allocated ESOP shares are included in basic common shares outstanding in the above table.

16. Segment Information

Presentation: NU is organized between the regulated companies and NU Enterprises businesses based on a combination of factors, including the characteristics of each business' products and services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. Cash flows for total investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC and the capitalized portion of pension expense or income. Segment information for all years presented has been reclassified to conform to the current period presentation, except as indicated.

The regulated companies segment, including the electric distribution, generation and transmission segments, as well as the gas distribution segment (Yankee Gas), represents approximately 99 percent, 87 percent and 75 percent of NU's total revenues for the years ended December 31, 2007, 2006 and 2005, respectively. CL&P's, PSNH's and WMECO's complete consolidated financial statements are included in NU's report on Form 10-K. PSNH's distribution segment includes generation activities. Also included in NU's report on Form 10-K is detailed information regarding CL&P's, PSNH's, and WMECO's transmission segments.

At December 31, 2007, the NU Enterprises business segment includes the following legal entities: 1) Select Energy (wholesale contracts), 2) NGS, 3) Boulos, and 4) NU Enterprises parent.

Other in the segment tables primarily consists of 1) the results of NU parent, which includes other income related to the equity in earnings of NU parent's subsidiaries and interest income from the NU Money Pool, which are both eliminated in consolidation, and interest income and expense related to the cash and debt of NU parent, respectively, 2) the revenues and expenses of NU's service companies, most of which are eliminated in consolidation, and 3) the results of other subsidiaries, which are comprised of the Rocky River Realty Company and the Quinnehtuk Company (real estate subsidiaries), Mode 1 Communications, Inc. and the results of the non-energy-related subsidiaries of Yankee Energy System, Inc. (Yankee Energy Services Company, Yankee Energy Financial Services Company, and NorConn Properties, Inc.).

Effective on January 1, 2007, financial information for the remaining operations of HWP that were not exited as part of the sale of the competitive generation business was included as part of the Other reportable segment as these operations were no longer considered part of NU Enterprises subsequent to the sale. Accordingly, HWP's remaining operations have been presented as part of the Other reportable segment for the year ended December 31, 2007.

As a result of the sale of NU Enterprises' retail marketing and competitive generation businesses, the financial information used by management was reduced to the remaining wholesale contracts, the operations of the remaining energy services businesses and NU Enterprises parent. As a result of exiting these businesses in 2006, the operations of NU Enterprises have been aggregated and presented as one reportable segment for the years ended December 31, 2007, 2006 and 2005.

NU's consolidated statements of income/(loss) for the years ended December 31, 2007, 2006 and 2005 present the operations for NGC, including certain components of NGS, Mt. Tom, SESI, a portion of the former Woods Electrical, SECI and Woods Network as discontinued operations. For further information and information regarding the exit from these businesses, see Note 3, "Assets Held for Sale and Discontinued Operations," to the consolidated financial statements.

Intercompany Transactions: Total Select Energy revenues from CL&P represented approximately $6.1 million and $53.4 million of total NU Enterprises' revenues for the years ended December 31, 2006 and 2005, respectively. Total CL&P purchases from Select Energy related to nontraditional standard offer contracts are eliminated in consolidation. There were no such transactions in 2007.

Total Select Energy revenues from WMECO represented $0.9 million and $36.3 million of total NU Enterprises' revenues for the years ended December 31, 2006 and 2005, respectively. Total WMECO purchases from Select Energy are eliminated in consolidation. There were no such transactions in 2007.

Select Energy purchases from NGC and Mt. Tom represented $160.7 million and $209.7 million for the years ended December 31, 2006 and 2005, respectively. On November 1, 2006, NU completed the sale of its 100 percent ownership in NGC stock and Mt. Tom.

Customer Concentrations: Select Energy billings related to contracts with NSTAR companies represented $296.7 million of total NU Enterprises' billings for the year ended December 31, 2005. There were no billings to NSTAR for the years ended December 31, 2007 and 2006. Select Energy provided basic generation service in the New Jersey market through 2007. In 2006 and 2005, Select Energy also provided service in the Maryland market. Select Energy billings related to these contracts represented $116.1 million, $404.4 million and $530 million for the years ended December 31, 2007, 2006 and 2005, respectively, of total NU Enterprises' billings. No other individual customer represented in excess of 10 percent of NU Enterprises' billings for the years ended December 31, 2007, 2006 and 2005. As these contracts expire, billings under a long-term contract with NYMPA will likely exceed 10 percent of NU Enterprises' billings in future periods.

Select Energy reported the settlement of all derivative contracts of the wholesale marketing business, including full requirements sales contracts and intercompany revenues, in fuel, purchased and net interchange power. This net presentation is a result of applying mark-to-market accounting to those contracts due to the decision to exit the wholesale marketing business.

Regulated companies revenues from the sale of electricity and natural gas primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer.

NU's segment information for the years ended December 31, 2007, 2006 and 2005 is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	For the Year Ended December 31, 2007						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$4,930.8	$ 514.1	$298.7	$ 97.7	$ 389.8	$ (408.9)	$ 5,822.2
Restructuring and impairment charges	—	—	—	(0.2)	—	—	(0.2)
Depreciation and amortization	(428.5)	(24.7)	(37.4)	(0.5)	(16.7)	0.8	(507.0)
Other operating expenses	(4,192.5)	(437.1)	(115.5)	(77.7)	(358.3)	405.6	(4,775.5)
Operating income	309.8	52.3	145.8	19.3	14.8	(2.5)	539.5
Interest expense, net of AFUDC	(167.9)	(19.0)	(36.7)	(8.9)	(33.3)	25.6	(240.2)
Interest income	6.0	—	3.8	2.4	34.3	(26.6)	19.9
Other income, net	27.6	1.2	13.0	—	158.3	(158.4)	41.7
Income tax expense	(47.9)	(11.9)	(41.8)	(1.7)	(3.0)	(3.1)	(109.4)
Preferred dividends	(4.0)	—	(1.6)	—	—	—	(5.6)
Income from continuing operations	123.6	22.6	82.5	11.1	171.1	(165.0)	245.9
Income from discontinued operations	—	—	—	0.6	—	—	0.6
Net income	$ 123.6	$ 22.6	$ 82.5	$ 11.7	$ 171.1	$ (165.0)	$ 246.5
Total assets (2)	$9,977.1	$1,309.1	$ —	$150.6	$4,154.3	$(4,009.3)	$11,581.8
Cash flows for total investments in plant (3)	$ 372.3	$ 57.6	$668.9	$ 0.9	$ 15.1	$ —	$ 1,114.8

	For the Year Ended December 31, 2006						
	Regulated Companies						
	Distribution (1)						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
Operating revenues	$5,336.0	$ 453.9	$216.0	$901.8	$ 355.0	$ (385.0)	$ 6,877.7
Restructuring and impairment charges	—	—	—	(8.5)	—	—	(8.5)
Depreciation and amortization	(387.2)	(22.7)	(29.8)	(0.7)	(18.8)	14.1	(445.1)
Other operating expenses	(4,652.5)	(401.0)	(93.6)	(1,068.3)	(335.9)	363.2	(6,188.1)
Operating income/(loss)	296.3	30.2	92.6	(175.7)	0.3	(7.7)	236.0
Interest expense, net of AFUDC	(160.1)	(16.5)	(22.4)	(26.9)	(37.1)	24.8	(238.2)
Interest income	8.4	—	0.4	5.1	32.8	(28.3)	18.4
Other income, net	31.9	1.4	6.8	0.1	205.2	(199.5)	45.9
Income tax benefit/(expense)	13.4	(3.2)	(16.4)	78.1	5.0	(0.6)	76.3
Preferred dividends	(4.3)	—	(1.2)	—	—	—	(5.5)
Income/(loss) from continuing operations	185.6	11.9	59.8	(119.3)	206.2	(211.3)	132.9
Income from discontinued operations	—	—	—	330.6	—	7.1	337.7
Net income	$ 185.6	$ 11.9	$ 59.8	$211.3	$ 206.2	$ (204.2)	$ 470.6
Total assets (2)	$9,223.3	$ 1,212.6	$ —	$276.8	$5,100.2	$ (4,509.7)	$ 11,303.2
Cash flows for total investments in plant (3)	$ 305.8	$ 87.6	$430.9	$ 25.8	$ 22.1	$ —	$ 872.2

(1) Includes PSNH generation activities.

(2) Information for segmenting total assets between electric distribution and transmission is not available at December 31, 2007 and 2006. On a NU consolidated basis, these distribution and transmission assets are disclosed in the electric distribution columns above.

(3) Cash flows for total investments in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income.

(Millions of Dollars)	Regulated Companies: Distribution (1): Electric	Regulated Companies: Distribution (1): Gas	Regulated Companies: Transmission	NU Enterprises	Other	Eliminations	Total
	For the Year Ended December 31, 2005						
Operating revenues	$4,836.5	$503.3	$167.5	$1,912.1	$353.0	$(426.2)	$ 7,346.2
Restructuring and impairment charges	—	—	—	(36.1)	—	—	(36.1)
Depreciation and amortization	(549.2)	(22.0)	(24.0)	(4.7)	(17.8)	13.6	(604.1)
Other operating expenses	(4,012.8)	(441.7)	(80.7)	(2,494.8)	(355.1)	426.9	(6,958.2)
Operating income/(loss)	274.5	39.6	62.8	(623.5)	(19.9)	14.3	(252.2)
Interest expense, net of AFUDC	(169.5)	(17.1)	(15.0)	(17.8)	(34.9)	15.7	(238.6)
Interest income	3.6	0.3	0.6	4.9	17.0	(19.2)	7.2
Other income, net	41.7	0.6	6.6	0.4	150.6	(152.5)	47.4
Income tax (expense)/benefit	(41.1)	(6.1)	(12.5)	234.4	18.4	(8.2)	184.9
Preferred dividends	(4.2)	—	(1.4)	—	—	—	(5.6)
Income/(loss) from continuing operations	105.0	17.3	41.1	(401.6)	131.2	(149.9)	(256.9)
Income from discontinued operations	—	—	—	4.4	—	—	4.4
Income/(loss) before cumulative effect of accounting change	105.0	17.3	41.1	(397.2)	131.2	(149.9)	(252.5)
Cumulative effect of accounting change, net of tax benefit	—	—	—	(1.0)	—	—	(1.0)
Net income/(loss)	$ 105.0	$ 17.3	$ 41.1	$ (398.2)	$131.2	$(149.9)	$ (253.5)
Cash flows for total investments in plant (2)	$ 400.9	$ 74.6	$247.0	$ 23.2	$ 29.7	$ —	$ 775.4

(1) Includes PSNH generation activities.

(2) Cash flows for total investments in plant included in the segment information above are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC, and the capitalized portion of pension expense or income.

CONSOLIDATED STATEMENTS OF QUARTERLY FINANCIAL DATA (UNAUDITED)

(Thousands of Dollars, except per share information)	Quarter Ended (a) (b) March 31,	June 30,	September 30,	December 31,
2007				
Operating Revenues	$1,703,518	$1,391,771	$1,450,978	$1,275,959
Operating Income	155,733	116,808	123,360	143,580
Income from Continuing Operations	76,407	46,012	50,182	73,295
(Loss)/Income from Discontinued Operations	(1,313)	2,541	(58)	(583)
Net Income	75,094	48,553	50,124	72,712
Basic Earnings/(Loss) Per Common Share:				
Income from Continuing Operations	$ 0.50	$ 0.30	$ 0.32	$ 0.47
(Loss)/Income from Discontinued Operations	(0.01)	0.01	—	—
Net Income	$ 0.49	$ 0.31	$ 0.32	$ 0.47
Fully Diluted Earnings/(Loss) Per Common Share:				
Income from Continuing Operations	$ 0.49	$ 0.30	$ 0.32	$ 0.47
(Loss)/Income from Discontinued Operations	(0.01)	0.01	—	—
Net Income	$ 0.48	$ 0.31	$ 0.32	$ 0.47
2006				
Operating Revenues	$2,143,599	$1,659,671	$1,590,982	$1,483,435
Operating Income	7,079	76,196	79,331	73,365
(Loss)/Income from Continuing Operations	(20,389)	15,353	104,429	33,543
Income from Discontinued Operations	10,283	6,889	7,020	313,450
Net (Loss)/Income	(10,106)	22,242	111,449	346,993
Basic (Loss)/Earnings Per Common Share:				
(Loss)/Income from Continuing Operations	$ (0.14)	$ 0.10	$ 0.67	$ 0.22
Income from Discontinued Operations	0.07	0.04	0.05	2.03
Net (Loss)/Income	$ (0.07)	$ 0.14	$ 0.72	$ 2.25
Fully Diluted (Loss)/Earnings Per Common Share:				
(Loss)/Income from Continuing Operations	$ (0.14)	$ 0.10	$ 0.67	$ 0.21
Income from Discontinued Operations	0.07	0.04	0.05	2.03
Net (Loss)/Income	$ (0.07)	$ 0.14	$ 0.72	$ 2.24

(a) The summation of quarterly EPS data may not equal annual data due to rounding.

(b) Amounts differ from those previously reported as a result of SECI meeting the criteria requiring discontinued operation presentation in the fourth quarter of 2007.

During the fourth quarter of 2007, NU determined that there was an error in certain assumptions supporting the initial FIN 48 adoption amounts recorded in the first quarter of 2007. The correction of the error resulted in the increase of the initial retained earnings reduction amount from $32.5 million to $41.8 million. This correction of the initial FIN 48 adoption accounting, which also affected certain liability balances reported in prior interim periods, did not have an effect on the income tax provision for 2007 and did not have a material impact on NU's consolidated financial statements for the quarterly periods ending March 31, 2007, June 30, 2007 and September 30, 2007.

SELECTED CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(Thousands of Dollars, except percentages and share information)	2007	2006	2005	2004	2003
Balance Sheet Data:					
Property, Plant and Equipment, Net	**$ 7,229,945**	$ 6,242,186	$ 6,417,230	$ 5,864,161	$ 5,429,916
Total Assets	**11,581,822**	11,303,236	12,567,875	11,638,396	11,216,487
Total Capitalization (a)	**6,667,920**	5,879,691	5,595,405	5,293,644	4,926,587
Obligations Under Capital Leases (a)	**14,743**	14,425	13,987	14,806	15,938
Income Data:					
Operating Revenues	**$ 5,822,226**	$ 6,877,687	$ 7,346,226	$ 6,480,684	$ 5,897,074
Income/(Loss) from Continuing Operations	**245,896**	132,936	(256,903)	70,423	77,105
Income from Discontinued Operations	**587**	337,642	4,420	46,165	44,047
Income/(Loss) Before Cumulative Effects of Accounting Changes, Net of Tax Benefits	**246,483**	470,578	(252,483)	116,588	121,152
Cumulative Effects of Accounting Changes, Net of Tax Benefits	**—**	—	(1,005)	—	(4,741)
Net Income/(Loss)	**$ 246,483**	$ 470,578	$ (253,488)	$ 116,588	$ 116,411
Common Share Data:					
Basic Earnings/(Loss) Per Common Share:					
Income/(Loss) from Continuing Operations	**$ 1.59**	$ 0.86	$ (1.95)	$ 0.55	$ 0.61
Income from Discontinued Operations	**—**	2.20	0.03	0.36	0.34
Cumulative Effects of Accounting Changes, Net of Tax Benefits	**—**	—	(0.01)	—	(0.04)
Net Income/(Loss)	**$ 1.59**	$ 3.06	$ (1.93)	$ 0.91	$ 0.91
Fully Diluted Earnings/(Loss) Per Common Share:					
Income/(Loss) from Continuing Operations	**$ 1.59**	$ 0.86	$ (1.95)	$ 0.55	$ 0.61
Income from Discontinued Operations	**—**	2.19	0.03	0.36	0.34
Cumulative Effects of Accounting Changes, Net of Tax Benefits	**—**	—	(0.01)	—	(0.04)
Net Income/(Loss)	**$ 1.59**	$ 3.05	$ (1.93)	$ 0.91	$ 0.91
Basic Common Shares Outstanding (Average)	**154,759,727**	153,767,527	131,638,953	128,245,860	127,114,743
Fully Diluted Common Shares Outstanding (Average)	**155,304,361**	154,146,669	131,638,953	128,396,076	127,240,724
Dividends Per Share	**$ 0.78**	$ 0.73	$ 0.68	$ 0.63	$ 0.58
Market Price – Closing (high) (b)	**$ 33.53**	$ 28.81	$ 21.79	$ 20.10	$ 20.17
Market Price – Closing (low) (b)	**$ 26.93**	$ 19.24	$ 17.61	$ 17.30	$ 13.38
Market Price – Closing (end of year) (b)	**$ 31.31**	$ 28.16	$ 19.69	$ 18.85	$ 20.17
Book Value Per Share (end of year)	**$ 18.79**	$ 18.14	$ 15.85	$ 17.80	$ 17.73
Tangible Book Value Per Share (end of year)	**$ 16.93**	$ 16.28	$ 13.98	$ 15.17	$ 15.05
Rate of Return Earned on Average Common Equity (%)	**8.6**	18.0	(10.7)	5.1	5.2
Market-to-Book Ratio (end of year)	**1.7**	1.6	1.2	1.1	1.1
Capitalization:					
Common Shareholders' Equity	**44%**	48%	43%	44%	46%
Preferred Stock	**2**	2	2	2	2
Long-Term Debt (a)	**54**	50	55	54	52
	100%	100%	100%	100%	100%

(a) Includes portions due within one year, but excludes rate reduction bonds.

(b) Market price information reflects closing prices as reflected by the New York Stock Exchange.

SELECTED CONSOLIDATED SALES STATISTICS (UNAUDITED)

	2007	2006	2005	2004	2003
Revenues: (Thousands)					
Regulated companies:					
Residential	**$2,558,547**	$2,409,414	$2,080,395	$1,707,434	$1,669,199
Commercial	**1,735,923**	1,977,444	1,727,278	1,429,608	1,411,881
Industrial	**412,381**	589,742	577,834	513,999	514,076
Wholesale	**392,675**	388,635	411,361	344,254	405,120
Streetlighting and Railroads	**45,880**	52,853	47,769	41,976	44,977
Miscellaneous and eliminations	**84,043**	133,925	159,402	143,431	(61,564)
Total Electric	**5,229,449**	5,552,013	5,004,039	4,180,702	3,983,689
Total Gas	**514,185**	453,894	503,303	407,812	361,470
Total – Regulated companies	**$5,743,634**	$6,005,907	$5,507,342	$4,588,514	$4,345,159
NU Enterprises:					
Retail	**$ —**	$ 583,829	$1,212,176	$ 857,355	$ 660,145
Wholesale	**25,992**	20,163	644,541	1,722,603	1,684,448
Generation	**—**	258,178	210,833	196,191	185,493
Services	**68,324**	39,887	102,327	117,500	96,963
Miscellaneous and eliminations	**3,354**	(243)	(257,750)	(245,745)	(223,440)
Total – NU Enterprises	**$ 97,670**	$ 901,814	$1,912,127	$2,647,904	$2,403,609
Other miscellaneous and eliminations	**(19,078)**	(30,034)	(73,243)	(755,734)	(851,694)
Total	**$5,822,226**	$6,877,687	$7,346,226	$6,480,684	$5,897,074

	2007	2006	2005	2004	2003
Regulated companies – Sales: (KWH – Millions)					
Residential	**15,051**	14,652	15,518	14,866	14,824
Commercial	**15,103**	14,886	15,234	14,710	14,471
Industrial	**5,635**	5,750	6,023	6,274	6,223
Wholesale	**3,855**	8,777	4,856	5,787	6,813
Streetlighting and Railroads	**353**	332	348	348	348
Total	**39,997**	44,397	41,979	41,985	42,679

	2007	2006	2005	2004	2003
Regulated companies – Customers: (Average)					
Residential	**1,697,073**	1,686,169	1,674,563	1,659,419	1,631,582
Commercial	**189,727**	188,281	195,844	194,233	186,792
Industrial	**7,291**	7,406	7,638	7,752	7,644
Streetlighting and Railroads	**3,855**	3,873	3,912	3,930	3,858
Total Electric	**1,897,946**	1,885,729	1,881,957	1,865,334	1,829,876
Gas	**202,743**	199,377	196,870	194,212	192,816
Total	**2,100,689**	2,085,106	2,078,827	2,059,546	2,022,692

TRUSTEES AND OFFICERS AS OF FEBRUARY 29, 2008

SHAREHOLDER INFORMATION

Northeast Utilities

Northeast Utilities operates New England's largest energy delivery system with approximately 1.9 million electric customers in Connecticut, New Hampshire and Massachusetts and approximately 200,000 natural gas customers in Connecticut. NU is the parent company of several companies, including the following public utility companies: The Connecticut Light and Power Company, Public Service Company of New Hampshire, Western Massachusetts Electric Company and Yankee Gas Services Company.

Shareholders

As of February 29, 2008, there were 47,633 common shareholders of record of Northeast Utilities holding an aggregate of 155,325,594 common shares.

Common Share Information

The common shares of Northeast Utilities are listed on the New York Stock Exchange. The ticker symbol is "NU," although it is frequently presented as "Noeast Util" and/or "NE Util" in various financial publications. The high and low daily closing prices and dividends paid for the past two years, by quarters, are shown in the chart below.

Year	Quarter	High	Low	Quarterly Dividend per Share
2007	**Fourth**	**$32.83**	**$27.98**	**$0.20**
	Third	**$29.42**	**$26.93**	**$0.20**
	Second	**$33.53**	**$27.37**	**$0.1875**
	First	**$32.77**	**$27.40**	**$0.1875**
2006	Fourth	$28.81	$23.38	$0.1875
	Third	$23.57	$20.84	$0.1875
	Second	$20.97	$19.24	$0.175
	First	$20.21	$19.25	$0.175

Transfer Agent and Registrar

The Bank of New York
Shareowner Services
480 Washington Boulevard
Jersey City, NJ 07310-1900
1-800-999-7269

Investor Relations

You can contact our Investor Relations Department:

Jeffrey Kotkin: 860-665-5154
Barbara Nieman: 860-665-3249
www.nu.com/investors

Shareholder Account Access

We have partnered with BNY Mellon Shareowner Services to offer you online access to your important shareowner communications in a single secure place. As an Investor ServiceDirect® (ISD) registered user, you may also enroll in MLink℠, which offers you immediate online access to your shareowner correspondence. Simply log in to ISD at www.bnymellon.com/shareowner/isd. Step by step instructions will prompt you through quick and easy enrollment.

Dividend Reinvestment Plan

Northeast Utilities offers a dividend reinvestment plan called BuyDIRECT. This plan is sponsored by the stock transfer agent and not only offers the reinvestment of dividends but provides both registered shareholders and interested first-time investors an affordable alternative for buying and selling NU shares. To request an enrollment package, please call 1-800-999-7269 or log on to www.bnymellon.com/shareowner/isd.

Direct Deposit for Quarterly Dividends

Direct deposit provides the convenience of automatic and immediate access to your funds, while eliminating the possibility of mail delays and lost, stolen or destroyed checks. This service is free of charge to you. Please call 1-800-999-7269 to request an enrollment form.

Annual Meeting

The Annual Meeting of Shareholders of Northeast Utilities will be held at 10:00 a.m. on May 13, 2008, at the offices of Public Service Company of New Hampshire, Energy Park, 780 No. Commercial Street, Manchester, New Hampshire, 03101.

Compliance with New York Stock Exchange Corporate Governance Rules

The Company's Annual Report on Form 10-K for 2007 contained the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002, and on June 7, 2007, the Company's Chief Executive Officer provided the New York Stock Exchange with the required annual written certification that he was not aware of any violations by the Company of the Exchange's corporate governance listing standards.

Form 10-K

Northeast Utilities will provide shareholders a copy of its 2007 Annual Report on Form 10-K, including the financial statements and schedules thereto, without charge, upon receipt of a written request sent to:

O. Kay Comendul
Assistant Secretary
Northeast Utilities
P.O. Box 270
Hartford, Connecticut 06141-0270

Option to receive your annual report and proxy materials electronically

In 2005, NU shareholders approved a change to the Declaration of Trust which allows us to offer electronic delivery of annual meeting materials. Shareholders interested in this option may log on to www.bnymellon.com/shareowner/isd. It would be helpful to have your NU Investor ID number on hand when you go online. Your Investor ID number can be found on the correspondence recently mailed to you by The Bank of New York or by calling 1-800-999-7269. NU will donate $5 to The American Chestnut Foundation, an organization devoted to restoring the American Chestnut tree to our forests, for every registered shareholder who signs up for electronic delivery of our 2009 annual meeting materials.

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