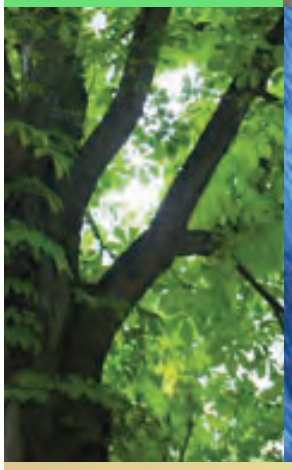

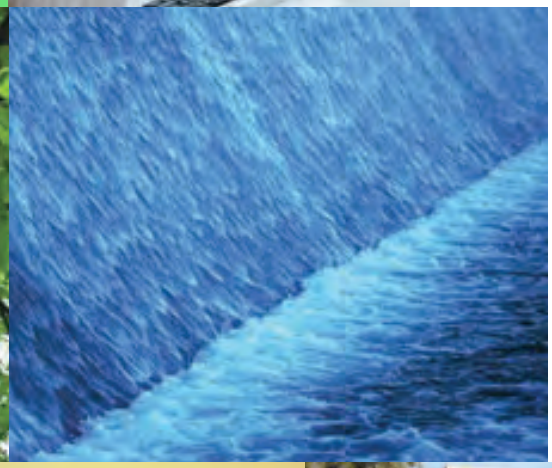

creating an environment for growth

2008 ANNUAL REPORT

Northeast Utilities

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creating an environment for growth

We're very proud of the financial and operational successes we achieved in 2008. We believe they are a springboard that makes Northeast Utilities one of the region's energy leaders for both today and tomorrow.

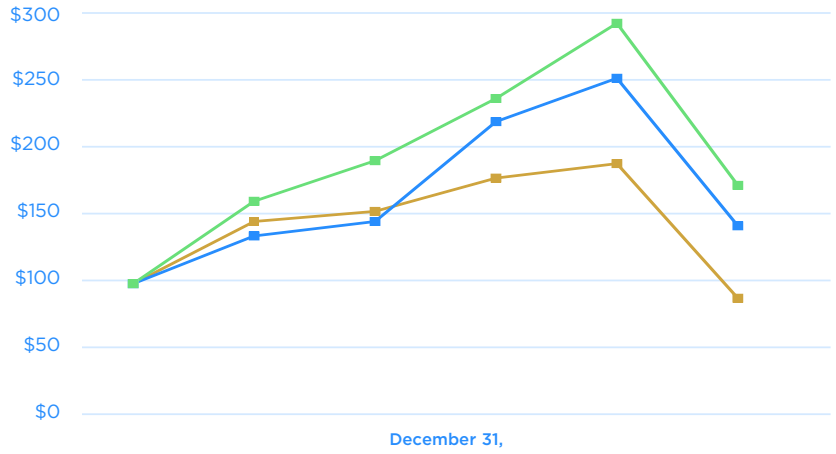
financial highlights

SELECTED FINANCIAL DATA

(Thousands of dollars, except share information and statistical data)	2008	2007
Operating Revenues	$ 5,800,095	$ 5,822,226
Operating Income	$ 590,765	$ 539,481
Net Income	$ 260,828	$ 246,483
Fully Diluted Earnings per Common Share	$ 1.67	$ 1.59
Fully Diluted Common Shares Outstanding (Weighted Average)	155,999,240	155,304,361
Dividends per Share	$ 0.825	$ 0.775
Sales of Electricity (Regulated Retail, KWH-millions)	34,883	36,142
Electric Customers (Average)	1,902,221	1,897,946
Gas Customers (Average)	204,834	202,743
Property, Plant and Equipment, Net	$ 8,207,876	$ 7,229,945
Market Capitalization as of Year End	$ 3,749,375	$ 4,855,548
Share Price as of Year End	$ 24.06	$ 31.31

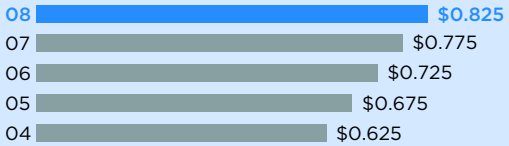
SHARE PRICE PERFORMANCE

(Assumes $100 invested on December 31, 2003, in Northeast Utilities (NU) common shares, S&P 500 Index and S&P Electric Utilities Index with all dividends reinvested)

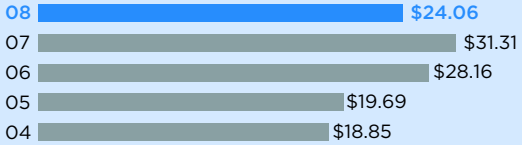


	2003	2004	2005	2006	2007	2008
S&P Electric Utilities	$100	$157	$185	$228	$280	$168
NU Common	$100	$133	$143	$212	$242	$140
S&P 500	$100	$143	$150	$173	$183	$ 90

DIVIDENDS PAID/SHARE
For the Years Ended December 31,



CLOSING SHARE PRICE At Year End



Charles W. Shivery

chairman's message

"Our vision for the future of our region is clear. We will take our company and our customers into the energy future with bold actions that produce results for today, and tomorrow."

To Our Customers, Communities and Shareholders:

Strong, well-managed, stable business organizations have never been more important to the future of our region — indeed, to the future of the United States — than they are during these challenging economic times. Northeast Utilities (NU) is such an organization, possessing the strength and stability to overcome short-term challenges and ready to capture the long-term opportunities that provide innovative solutions for our customers. We're very proud of the financial and operational successes we achieved in 2008. We believe they are a springboard that makes NU one of the region's energy leaders for both today and tomorrow.

Nowhere was this more evident than in how we dealt with Mother Nature last December when our region was battered by an epic ice storm, providing further testimony to the strength and determination of our company. The efficiency with which NU employees carried out our emergency response plan demonstrated the pride we take in our work. It also shows that we are capable of transforming adversity into an exhibition of why NU will continue to be successful in the future.

In addition, we simply did not let harsh economic and natural events of 2008 knock us off stride. We delivered value to our customers, communities and shareholders.

For customers, our $1.3 billion in capital expenditures in 2008 alone produced a more reliable transmission and distribution system, reduced congestion costs and improved overall safety. In addition, despite an increase in the number of storms, NU was able to retain solid overall system reliability at the industry average, and reliability at our largest company, The Connecticut Light and Power Company (CL&P), was better than the industry average.

companies. In 2008, we continued to increase our dividend at a pace that is faster than the industry average, and in the first quarter of 2009, we further increased our dividend by 12 percent, at a time when many companies are cutting dividends. We believe these dividend increases underscore the confidence your Board and management have in the successful execution of our business strategy.

"Northeast Utilities stands as an industry leader in transmission construction, energy efficiency, emergency response, and many other categories, and our efforts have won both national and international acclaim."

For our communities, we continued to provide jobs by hiring over 500 new employees in 2008 and provided funding for various not-for-profit and civic organizations across our tri-state service area. For example, in Connecticut, CL&P donated $1.36 million in local grants and other support, while in New Hampshire, Public Service Company of New Hampshire (PSNH) donated nearly $600,000 to the not-for-profit sector. In Massachusetts, Western Massachusetts Electric Company (WMECO) donated more than $480,000. Additionally, by purchasing $5.7 million in tax credits through the Connecticut Low-Income Housing Tax Program, CL&P helped fund housing for more than 500 families and individuals.

For our shareholders, we delivered a better share price performance than most other utilities and other listed

We received additional good news on March 5, 2009, when Standard & Poor's announced that it was adding NU to the S&P 500 — one of the world's most recognized stock indices. We believe this recognition will increase the breadth of our potential shareholder base.

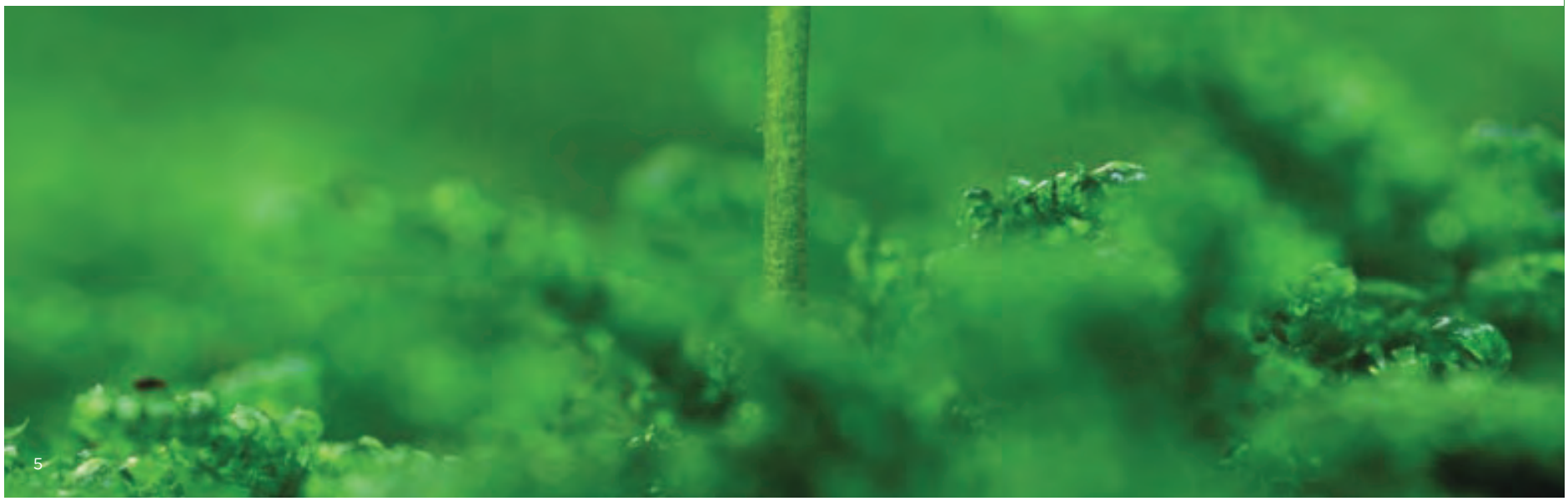
Our strong 2008 performance enables us to continue to make meaningful progress as an energy company on the leading edge of delivering sustainable solutions to our customers, communities and shareholders.

Operational Success: Going Above and Beyond

Operating a large, modern energy company such as NU requires daily discipline and a well-coordinated team dedicated to carrying out our business plan. Even then, there are many occasions when members of that team reach down and produce even more.

We know what we have to do if our region is to enjoy a safe, reliable and clean energy 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."



We achieved a notable level of operational excellence when we completed and put into service three major transmission projects in southwest Connecticut, in aggregate ahead of schedule and under budget. These projects include the 69-mile Middletown-Norwalk transmission line; the Glenbrook Cables project; and the Long Island Replacement Cable project, an 11-mile, 138-kilovolt undersea cable linking Norwalk, Connecticut, and Northport, New York. Our Bethel-Norwalk project was completed in 2006. Energizing the four projects was not only a source of company pride but also a major benefit for our customers who depend daily on the power we deliver.

These transmission projects provide our customers with enhanced reliability, and they help to mitigate costly congestion in this region. The early completion of these projects also contributed to the company's financial performance as they generated income sooner than expected.

Today, NU stands as an industry leader in transmission construction, energy efficiency, emergency response, and many other categories, and our efforts have won both national and international acclaim. From our award-winning conservation and load management efficiency programs that have served nearly 400,000 NU customers and save over $50 million in annual electric energy costs, to a 2008 Platts Global Energy Award for excellence in our execution of transmission construction, our noteworthy accomplishments exemplify the vision and leadership that characterize our company.

Meeting Customers' Energy Needs, Today and Tomorrow

Our commitment to supporting the region's growth requires an equally strong commitment to implementing sustainable solutions that meet the energy needs of today. It is our responsibility as an energy leader to protect our environment. Achieving this balance requires an increased reliance on renewable energy sources, and we are continuing to take noteworthy strides toward a sustainable energy future for our customers as well as our company.

Whether it's developing innovative solar projects in Massachusetts or operating a renewable wood-burning power plant in New Hampshire, we are already fulfilling our vision of creating sustainable solutions for our energy future. Demonstrating our commitment to the search for a portfolio of new solutions, late last year NU, joined by NSTAR, asked the Federal Energy Regulatory Commission to approve our concept for a new participant-funded transmission line to connect to Hydro-Québec in eastern Canada.

In addition to developing plans for the transmission line, we have begun negotiations with Hydro-Québec on the terms of a power purchase contract that will allow us to provide economic value as well as clean, low-carbon-emitting energy to New England, delivering real benefits to our customers, shareholders and the region. We see this as a project that is needed to further diversify the region's generation mix, reduce greenhouse gas emissions and move forward to meet ambitious environmental goals.

Our Region is Our Home, and Yours

Whether in Connecticut, western Massachusetts or New Hampshire, we live where we work and we take seriously our responsibility to be good neighbors. Of course, that translates before all else into a determination to provide safe, reliable energy to our customers at a reasonable cost and always to be mindful that we must be stewards of our region's environment.

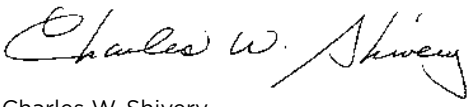
We strive to help the people of our region in other ways, too. Again in 2008, the Northeast Utilities Foundation donated $1 million to worthwhile regional activities, augmented by some $2.4 million in contributions made by our operating companies. And, as they did in 2007, our employees across our three-state territory donated more than $2 million themselves, while also volunteering their time and energy to help local organizations.

NU is also a major contributor to the economies of the three states in which it operates. Our operating companies paid a combined total of over $125 million in local property taxes last year, thereby supporting important programs in many of our communities.

The Energy to Make a Difference

We are at a transitional, pivotal time in the energy industry. We know what we have to do and we know how to do it — so that our region enjoys safe, reliable and clean energy. Our vision for the future of our region is clear. We will take our company and our customers into the energy future with bold actions that produce results for today, and tomorrow.

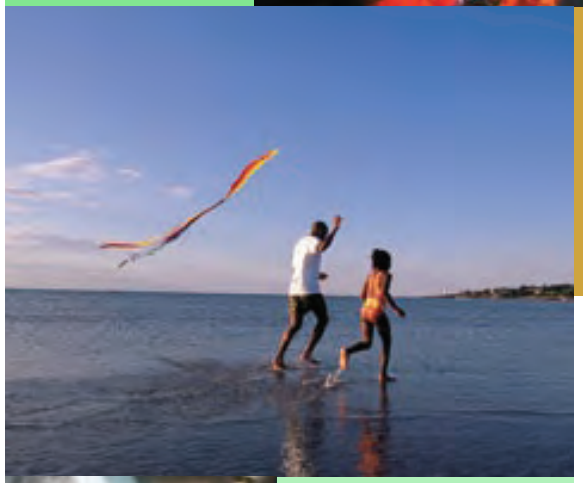
Sincerely,



Charles W. Shivery
Chairman, President and Chief Executive Officer

March 6, 2009

forging a sustainable energy future



Northeast Utilities believes it is now more important than ever to ensure we maintain and grow our commitment to sustainability and environmental stewardship. In fact, industry experts and studies suggest that businesses demonstrating a firm dedication to sustainability during hard times often outperform industry peers financially.

In its broadest sense, "sustainability" means the responsibility we all share to protect and improve not just our environment, but all aspects of our communities, our economy and our individual lives. For NU, that includes continuing to redefine our impact on the environment by encouraging the wise use of energy and providing energy from cleaner resources. Further, it means operating every aspect of our business in a manner that ensures we can meet our stakeholders' various expectations, now and in the future. Thus, sustainability is all about solutions for today and for tomorrow.

Environmentally, we must continue to make progress in taking carbon out of the energy equation by moving toward lower overall energy use and increasing the use of clean energy resources such as renewable and hydroelectric power. This will help us to reduce our reliance on carbon-emitting fuels. And, over time, we will actively support efforts to use cleaner energy sources to cost-effectively fuel our cars and heat our homes.

Like the state governments in our region, NU and its operating companies have made a commitment to sustainability and to demonstrating innovation and leadership in reducing greenhouse gas emissions. Our investment plans are in harmony with the energy policies of the states we serve. And they are also consistent with the themes we hear from the new administration in Washington.

first time since deregulation, to own and operate up to 50 megawatts of solar production.

WMECO's solar power initiative is a direct result of the passage of the Green Communities Act. WMECO is seeking regulatory approval to invest approximately $42 million to install at least six megawatts of solar production, potentially growing to 50 megawatts, at multiple sites in western Massachusetts.

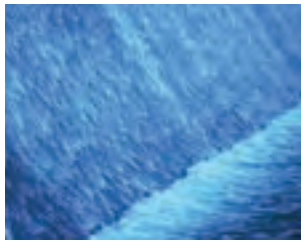
"In New Hampshire, our Clean Air Project at Merrimack Station will dramatically reduce sulfur dioxide emissions by 90 percent and mercury by 80 percent from PSNH's generation fleet, while continuing to provide the region with needed fuel diversity."

At the state level, sustainability is now at the forefront as governments in our region have moved aggressively to protect the environment. Connecticut passed "An Act Concerning Connecticut Global Warming Solutions" mandating reductions in state greenhouse gas emissions and recommending strategies, regulatory actions and policies to achieve the reductions. New Hampshire has a law establishing a Climate Change Policy Task Force responsible for developing a climate change action plan.

Massachusetts enacted its "Green Communities Act" requiring that 80 percent of the Regional Greenhouse Gas Initiative auction proceeds be earmarked for energy efficiency and demand response; removing the cap on utility expenditures on energy efficiency and demand response; and allowing utilities, for the

If approved, the first solar facilities could be operating in 2010. In addition to the potential for long-term benefits to our customers and communities while also providing competitive returns for investors, we believe the elements of this solar power initiative can serve as a valuable "blueprint" for other renewable technologies across New England. In addition, we responded to the increased funding available to bolster our energy-efficiency efforts by 67 percent in 2009 to help customers in western Massachusetts make better use of energy resources. We plan to develop a much more expanded energy conservation program for WMECO for 2010 — 2012.

In New Hampshire, our Clean Air Project at Merrimack Station will dramatically reduce sulfur dioxide emissions by 90 percent and mercury by 80 percent



We see sustainability for our industry as redefining our impact on the environment by providing energy from cleaner resources.

"Environmental stewardship is a core value of NU. It includes our commitment to promoting the efficient use of energy."

from PSNH's generation fleet, while continuing to provide the region with needed fuel diversity. The project — the installation of a wet scrubber at our Merrimack Station — is scheduled for completion in 2012 and will support 300 construction jobs. When the project is finished, it will make this power plant one of the cleanest coal-burning energy facilities in the nation. Since coal is economical and its cost is relatively stable, this is an important component of our strategy of reducing the impact on the environment while continuing to provide our customers with cost-effective and reliable energy.

Our transmission investments give the region a more reliable, secure and modern grid. They also can provide the electrical highway to bring low-carbon and renewable power to the load centers of New England from northern New Hampshire and Canada.

Building on our award-winning transmission expertise, late last year we announced another innovative proposal: a memorandum of understanding with NSTAR and Hydro-Québec to build a new high-voltage, direct current, participant-funded transmission line from Québec to central or southern New Hampshire. As mentioned earlier in this report, NU and NSTAR filed an application last December for a declaratory ruling from the Federal Energy Regulatory Commission. It represented our first formal step toward making the high-voltage line a reality. We believe this project, as conceived, could allow New England to meet nearly one-third of its greenhouse gas reduction goals.

We also have planned pilot programs in Connecticut and Massachusetts to demonstrate the benefits of automated metering infrastructure and "smart grid" technology to provide our customers with more choices, information and control over their electric consumption, and to reduce the energy losses through our distribution system. CL&P's "Plan-It Wise" pilot program will launch in summer 2009, and we intend to file plans with the Massachusetts Department of Public Utilities in April 2009 for a pilot focused on the unique needs of our western Massachusetts customers.

In addition, we are taking concrete steps to help prepare our region for the introduction of next-generation electric vehicles, anticipated to be brought to market in 2010. We are working with the Clean Cities Coalition, the Electric Power Research Institute and General Motors, and we have applied for a grant from the U.S. Department of Energy to begin the development of public charging infrastructures in Connecticut and Massachusetts.

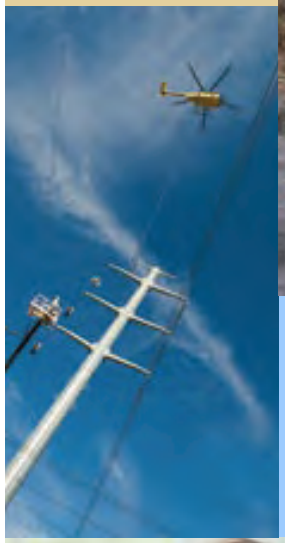
Not only are these initiatives consistent with both federal and New England energy policy, they represent more diversity in our future capital expenditures, as we complement our traditional electric distribution and transmission investments with innovative solutions to meet broader energy policy objectives. We continue to believe that NU can and will take a leadership role when carrying out these policies in New England.

NU's environmental policy serves as the foundation for our Environmental Management System (EMS), which is modeled after the internationally accepted ISO 14001:2004 standard. By adhering to the EMS, NU anticipates and meets growing environmental performance expectations, mitigates risks and ensures ongoing compliance with federal and state requirements. NU has achieved ISO 14001 certification at 44 facilities and departments, including all CL&P and WMECO locations.

Environmental stewardship is a core value of NU. It includes our commitment to promoting the efficient use of energy. In 2008, NU worked with a combined conservation and load management budget of about $113 million and provided conservation services to more than 390,000 customers. We also estimate that these energy-efficiency programs of CL&P, PSNH and WMECO will save a combined lifetime total of approximately 3.5 billion kilowatt-hours, avoiding the emissions of about 1.9 million tons of carbon dioxide. Commercial and industrial natural gas programs were also added in 2008, helping Yankee Gas Services Company (Yankee Gas) customers save energy, money and the environment.

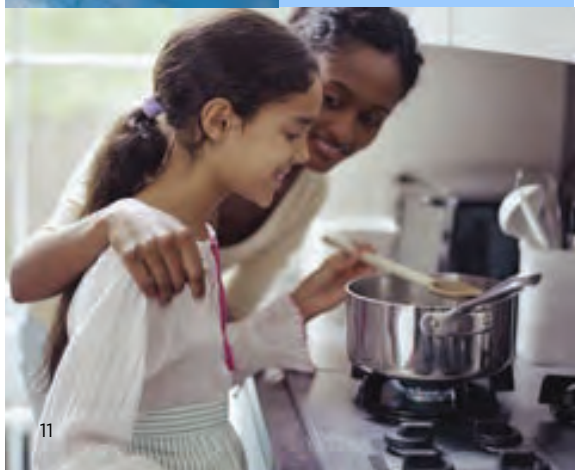
NU has been recognized by many national and international organizations for the success of the energy-efficiency programs we offer. For example, CL&P and WMECO received the 2008 ENERGY STAR® Sustained Excellence Award from the U.S. Environmental Protection Agency for their continued leadership in this area.

meeting our customers' energy needs today and every day



Perhaps as you read these words you are looking at the NU Web site (www.nu.com), where this report and much other useful information about the company are available. If so, you are using energy. You probably didn't even think about that until you read this. And that's the point. As the use of energy changes and diversifies, the need for reliable, safe energy will remain a staple of our daily lives.

Our job at NU is to ensure that our customers have the power they need when they need it. That's why, despite the economic downturn, we invested $1.3 billion in our region's infrastructure in 2008. These investments help create a more reliable grid for all our customers and make the businesses in our three states more competitive over the long run.



In 2008, we also completed our $1.6 billion transmission investment in southwest Connecticut, concluding with the Middletown-Norwalk project, one year ahead of schedule and $100 million below budget.

The southwest Connecticut transmission projects are providing Connecticut with a more robust and reliable electric grid. Additionally, they have significantly mitigated congestion in a state whose electric customers had been paying in excess of about $150 million annually in congestion costs, due to bottlenecks within Connecticut. Our transmission construction experience and track record of success will help us as we move on to siting of our proposed New England East-West Solution (NEEWS) projects.

Along with National Grid USA, Inc., we are advancing these related projects, which will improve reliability and provide a strong transmission backbone for moving power throughout southern New England. The NEEWS projects will also better enable our region to gain access to renewable power generation.

On the natural gas side of our business, sales at our subsidiary, Yankee Gas, grew by 2.1 percent in 2008, driven by increased installation of distributed generation and conversions of oil furnaces to natural gas as the fuel of choice. We increased conversions by some 400 percent in our service territory last year, significantly lowering the carbon footprint of these homes and businesses.

"The NEEWS projects will also better enable our region to gain access to renewable power generation."

Our job at NU is to ensure that our customers have the power that they need when they need it.

good people serving the people of our region

Our commitment to supporting the region's growth requires an equally strong commitment to the communities we serve. And the communities we serve are more than our places of work — they are where we live. We can thus never lose sight of the fact that the daily work done by our more than 6,000 employees, some of whom routinely take on dangerous assignments working with live power lines, is done as a service to the region. And giving back to communities is second nature for NU and its employees.

In these troubling economic times, we at NU are mindful of the need to balance energy, environmental and other initiatives with the cost realities that face our customers, particularly those with limited incomes. Each of our operating subsidiaries offers innovative programs and services to help customers with their energy needs by working in partnership with social service agencies to deliver energy assistance, conservation strategies and affordable payment plans. Furthermore, in 2008, we contributed over $200,000 to not-for-profit organizations that provide emergency assistance to the elderly, disabled and limited-income working families in need of help paying their energy bills.

Also in 2008, more than 700 NU employees participated in the annual United Way Day of Caring. Not-for-profit agencies and organizations benefited from these volunteers who spent the day performing hands-on tasks such as landscaping, preparing meals and visiting with senior citizens. Further, our employees donated thousands of hours in their cities and towns as mentors, scout leaders, coaches, tutors and volunteer fire fighters. Others are active on boards of hospitals, as well as chambers of commerce, the arts, and education and alumni associations.

The Northeast Utilities Foundation continues to embrace its worthy partners. One such partner is the Connecticut Science Center, a world-class science learning center in Hartford that is scheduled to open in 2009. The Foundation announced a grant of $1 million to the Science Center in 2007, and followed that with an additional $500,000 in 2008 to fund the Center's "Forces in Motion," a gallery showcasing the physics of motion. Overlooking the Connecticut River, the Center will be a must-see attraction, encouraging people of all ages to imagine, discover and explore the world of science.

NU and its operating companies in Connecticut, western Massachusetts and New Hampshire play a critically important role in the health and economic well-being of the region's residents, businesses and institutions. Likewise, the well-being of those who live and work in our region is vital to our success as a company. NU will continue to invest in its communities and lead the way in energy innovation and community development on behalf of its customers.

"Our commitment to supporting the region's growth requires an equally strong commitment to the communities we serve."

The well-being of those who live and work in our region is vital to our success as a company.

responding to nature's wrath

The events that began to unfold on December 11, 2008, demonstrated our ability to respond effectively and responsibly to a monstrous regional calamity. A severe ice storm crippled large parts of New Hampshire and Massachusetts. During the night of December 11, power was knocked out to about 65 percent of PSNH's customers and more than 20 percent of WMECO's customers. The ice storm snapped tree limbs, broke or damaged more than 18,000 distribution poles, and required us to replace 166 miles of distribution lines throughout the region.

But our biggest concern was for our customers, particularly the more than 400,000 who lost power in the storm. Two severe snowstorms, coupled with high winds, hit New Hampshire almost as soon as the ice storm finished, giving our recovery teams an even more daunting challenge.

The recovery efforts demonstrated the dedication of our employees, who worked 16-hour days right up until Christmas to restore service to our customers. It also illustrated the benefit of our three-state company as hundreds of Connecticut-based workers aided their northern colleagues to rebuild large sections of New Hampshire and western Massachusetts distribution systems. It marked the largest restoration effort in PSNH history. Through it all, no major safety incidents occurred during the multiple-day, multiple-state emergency operation.

The storms challenged us to communicate effectively with our customers, especially those living without power. Our new, technology-driven customer information system enabled us to handle the avalanche of calls, many of them from New Hampshire where the storm's impact was fiercest. For the first time, we took advantage of "new media," using Twitter, a free Internet social messaging service, to reach PSNH customers with timely postings and podcasts.

The Edison Electric Institute recently honored NU as a winner of the association's "Emergency Response Award" for our outstanding efforts to restore electric power to our customers in the wake of this catastrophic ice storm.

2008 FINANCIAL INFORMATION

MANAGEMENT'S DISCUSSION AND ANALYSIS 17

Management discusses in detail the financial results and condition of the company, providing investors with an opportunity to view the company through the eyes of management.

COMPANY REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING 45

Management accepts responsibility for the preparation, integrity, and fair presentation of the accompanying consolidated financial statements and concludes that the internal controls over financial reporting were effective as of December 31, 2008.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM 46

The report of Deloitte & Touche LLP

CONSOLIDATED BALANCE SHEETS 47

The company's total assets were $14 billion at December 31, 2008.

CONSOLIDATED STATEMENTS OF INCOME AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME 48-49

The company's net income for 2008 was $260.8 million while comprehensive income for 2008 was $214.2 million.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY 50

In 2008, the company declared $129 million in common dividends, and common shareholders' equity totaled $3 billion at December 31, 2008.

CONSOLIDATED STATEMENTS OF CASH FLOWS 51

The company's cash and cash equivalents at December 31, 2008, were $89.8 million, an increase of $74.7 million from a year earlier, while the company's operating cash flows totaled $649.4 million in 2008.

CONSOLIDATED STATEMENTS OF CAPITALIZATION 52

At December 31, 2008, the company's total capitalization was $7.2 billion, which included $4.1 billion in long-term debt, $116.2 million in non-redeemable preferred stock and $3 billion in common shareholders' equity.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS 52

The company explains in detail the events, actions, projects, processes and judgments that produced the amounts reflected in the accompanying consolidated financial statements.

TRUSTEES AND OFFICERS 89

A listing of the company's Trustees and Officers

SHAREHOLDER INFORMATION 90

Summarized shareholder information

Management's Discussion and Analysis

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this annual report. References in this annual report to "NU," "we," "us" and "our" refer to Northeast Utilities and its consolidated subsidiaries. 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 discussed below 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 results and 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 operating performance.

The discussion below also includes non-GAAP measures referencing our 2008 earnings and EPS excluding a significant charge resulting from the settlement of litigation with Consolidated Edison, Inc. (Con Edison), and our 2006 earnings and EPS excluding two significant, discrete impacts, which are the gain from the sale of our competitive generation business and a reduction in income tax expense at The Connecticut Light and Power Company (CL&P) pursuant to a Private Letter Ruling (PLR) issued by the Internal Revenue Service (IRS). We use these non-GAAP measures to more fully explain and compare the 2008, 2007 and 2006 results without including the impact of these items. Due to the nature and significance of these amounts, management believes that this non-GAAP presentation is more representative of our performance and provides additional and useful information to investors in analyzing historical and future performance. These measures should not be considered as alternatives to reported net income or EPS determined in accordance with GAAP as indicators of operating performance.

Reconciliations of the above non-GAAP measures to the most directly comparable GAAP measures of consolidated fully diluted EPS and net income are included under "Financial Condition and Business Analysis-Overview-Consolidated" and "Financial Condition and Business Analysis-Future Outlook" in this Management's Discussion and Analysis.

Financial Condition and Business Analysis

Current Economic Conditions: As widely reported, the capital and credit markets are experiencing uncertainty and volatility to an unprecedented extent. This disruption has weakened and may continue to weaken economic conditions in parallel with the general decline in consumer confidence in the Northeast and throughout the United States. So far, the limited access to capital and higher cost of capital for businesses and consumers has reduced spending, resulted in job losses, and pressured economic growth for the foreseeable future. These weak economic conditions have affected and could continue to affect our revenues and future earnings growth and could result in greater risk of default by our counterparties, including customers, weaker sales growth, increased energy conservation, and higher bad debt expense, among other things. The weak economic conditions are also expected to put pressure on our ability to obtain distribution rate relief or to receive approvals on major transmission projects that will ultimately increase customer rates. We have included our best estimate of the impacts of these factors in the assumptions that were used to develop our earnings guidance; however, we are unable to predict the ultimate impact of these conditions on our results of operations, financial position, or liquidity.

In addition, we expect to make significant levels of investments in our capital projects in 2009 through 2013. The disruption in the capital markets has limited some companies' ability to access the capital and credit markets to support their operations and refinance debt and has led to higher financing costs compared to recent years. We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for our capital requirements, including construction costs. We believe our current credit ratings will allow us to have access to the capital markets as needed (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). However, events beyond our control, such as the disruption in global capital and credit markets that occurred in September 2008, may create further uncertainty that could increase our cost of capital or impair our ability to access the capital markets. In addition, certain of NU's subsidiaries rely, in part, on NU parent for access to capital. Circumstances that limit NU parent's access to capital could impair its ability to provide those companies with needed capital. At this point in time, while the impact of continued market volatility and the extent and impacts of the ongoing economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity.

Executive Summary

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

Results, Strategy and Outlook:

- We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share.
- After payment of CL&P preferred dividends, 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 $289.1 million, or $1.85 per share, in 2008, compared with $228.7 million, or $1.47 per share, in 2007. The 2008 results included earnings of $150.8 million in the distribution segment (which includes the generation segment of PSNH and gas distribution segment of Yankee Gas), and $138.3 million in the transmission segment. In 2007, our distribution segment earned $146.2 million and our transmission segment earned $82.5 million.
- Our competitive businesses, or NU Enterprises, Inc. (NU Enterprises), earned $13.1 million, or $0.08 per share, in 2008, compared with $11.7 million, or $0.08 per share, in 2007.
- NU parent and other companies recorded net expenses of $41.4 million, or $0.26 per share, in 2008, compared with net income of $6.1 million, or $0.04 per share, in 2007. Excluding the litigation settlement charge related to Con Edison, NU parent and other companies recorded net expenses of $11.6 million, or $0.07 per share, in 2008.
- In 2008, CL&P completed the final three of its four major transmission projects in southwest Connecticut. The projects were completed approximately $80 million below their $1.68 billion budget and the final project was completed approximately one year ahead of schedule. Also, in October 2008, CL&P and WMECO filed siting applications to build their portions of the $714 million Greater Springfield Reliability Project, which is the largest project within the New England East-West Solutions (NEEWS) series of projects. Refer to "Business Developments and Capital Expenditures - Regulated Companies - Transmission Segment" in this Management's Discussion and Analysis for further discussion.
- We project consolidated 2009 earnings of between $1.80 per share and $2.00 per share, including earnings

of between $1.00 per share and $1.10 per share at our distribution segment, between $0.85 per share and $0.90 per share at our transmission segment and between $0.00 per share and $0.05 per share at our remaining competitive businesses, and net expenses of $0.05 per share at NU parent and other companies. This projection assumes the issuance of between $250 million and $300 million of additional equity in mid-2009. Our 2009 forecast reflects our expectations of lower electric sales and higher pension and uncollectible expense than what we experienced in 2008, due to current economic conditions.

- During 2008, we announced that our corporate headquarters will be relocated from its current location in Berlin, Connecticut to a recently purchased office building in downtown Hartford, Connecticut. We expect to move approximately 175 corporate employees into Hartford by the summer of 2009.

Legal, Regulatory and Other Items:

- On January 28, 2008, the Connecticut Department of Public Utility Control (DPUC) approved an increase in CL&P's annual distribution rates of $77.8 million, effective February 1, 2008, and an incremental $20.1 million annual increase, effective February 1, 2009.
- On March 13, 2008, we entered into a settlement agreement with Con Edison that settled all claims in the civil lawsuit between Con Edison and us relating to our proposed but unconsummated merger. Under the terms of the settlement agreement, we paid Con Edison $49.5 million on March 26, 2008, which resulted in an after-tax charge of $29.8 million. This amount is not recoverable from ratepayers.
- On March 24, 2008, the Federal Energy Regulatory Commission (FERC) issued a rehearing order confirming its initial decision setting the base return on equity (ROE) for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the New England Independent System Operator (ISO-NE) Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million in transmission segment earnings related to this order.
- On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund to customers approximately $5.8 million in previous recoveries through Yankee Gas' Purchased Gas Adjustment (PGA) clause. Yankee Gas results for 2008 reflect an after-tax charge of $3.5 million associated with that decision.
- On July 16, 2008, the Massachusetts Department of Public Utilities (DPU) issued a decision requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal to fully decouple distribution revenues from kilowatt-hour (KWH) sales.
- On July 17, 2008, the FERC confirmed the 100 basis point incentive ROE for the Middletown-Norwalk transmission project and approved an additional 50 basis points, capped at the overall ROE limit, to the ROE CL&P will earn on the advanced technology aspects of its 24-mile underground portion of the 69-mile project, which entered service in December 2008. This decision adds approximately $0.9 million to CL&P's annual transmission segment earnings beginning in 2009.
- In October 2008, CL&P had entered into contracts for differences (CfDs) with developers of three peaking generation units approved by the DPUC. These units will have a total of approximately 500 megawatts (MW) of peaking capacity. As directed by the DPUC, CL&P and The United Illuminating Company (UI) entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P's portion of the costs and benefits will be paid by or refunded to its customers.
- On November 17, 2008, the FERC issued an order granting incentives and rate amendments to National Grid USA and us for NEEWS transmission upgrade components. Our portion of these components is currently estimated to comprise about $1.41 billion of the total $1.49 billion cost estimate for our portion of NEEWS. The approved incentives included cash recovery through rates for 100 percent construction work in progress (CWIP), an incentive ROE of 12.89 percent and recovery of prudently incurred costs associated with project elements that may be cancelled for reasons outside of our control or National Grid USA's control.
- On December 11, 2008, a major ice storm struck portions of New England causing approximately $100 million of damage to PSNH's, WMECO's and CL&P's distribution systems. This was the most severe ice storm in PSNH's history, and most of the $100 million in damages was to its system. CL&P's system suffered the least amount of damage from the storm. Some of these costs are covered by insurance, a small portion was expensed in 2008 and the balance should be recoverable in future rates and has been deferred or capitalized. None of the companies experienced a material impact to their results of operations from this storm.
- On December 12, 2008, NU and NSTAR submitted a joint petition for a declaratory order to the FERC to allow NU and NSTAR to enter into a bilateral transmission services agreement with H.Q. Energy Services (U.S.) Inc. (HQUS), a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR would sell 1,200 MW of firm electric transmission service over a newly constructed, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver into New England this same amount of firm electric power from Canadian low-carbon energy resources. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. Our portion of this project is currently estimated to cost approximately $525 million. Refer to "Business Development and Capital Expenditures" in this Management's Discussion and Analysis for further discussion.
- On January 15, 2009, the DPUC issued a final decision reversing its December 2005 draft decision regarding CL&P's proposed methodology to calculate the variable incentive portion of its transition service procurement fee in 2004. The final decision concluded that CL&P was not eligible for this procurement incentive. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings. A $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers was established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

Liquidity:

- While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for NU parent and our regulated companies are all stable. Our companies have modest risk of calls for collateral. We also have only one series of bonds maturing before 2012 ($50 million in the second quarter of 2009), and capital expenditures projected for 2009 are significantly less than 2008. No cash contributions to our pension plan are required during 2009; however, due to the substantial decrease in our pension plan assets in 2008 and unless there is a change in current funding requirements, we will be required to make an estimated $150 million contribution in 2010. Refer to "Liquidity - Impact of Financial Market Conditions" in this Management's Discussion and Analysis for further discussion.

- Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007. We were successful in meeting our extensive 2008 capital plan. In 2009, we expect cash capital expenditures to be approximately $880 million, primarily because of lower transmission capital expenditures at CL&P.
- We issued $760 million of long-term debt in 2008 at rates of between 5.65 percent and 6.9 percent, and $250 million in February 2009 at a rate of 5.5 percent. We expect further external financings totaling $400 million to $450 million in mid-2009 (or earlier depending on market opportunities), including approximately $150 million of long-term debt by PSNH, subject to regulatory approval, and between $250 million and $300 million of additional equity by NU parent. Refer to "Liquidity" in this Management's Discussion and Analysis for further discussion.
- On June 30, 2008, due to the availability and lower relative cost of other liquidity sources, CL&P chose to terminate the arrangement under which CL&P could sell to a financial institution up to $100 million of accounts receivable and unbilled revenues.
- After rate reduction bond (RRB) payments included in financing activities, we had cash flows provided by operations in 2008 of $418.5 million, which represented an increase of $429.8 million from 2007. This increase was primarily due to the absence in 2008 of approximately $400 million in tax payments in 2007 related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. Refer to "Liquidity - Consolidated" in this Management's Discussion and Analysis for further discussion.
- In 2009, we project operating cash flows of approximately $500 million, after repayment of RRBs. This projection does not include any contributions to our pension plan, as they are not required to be paid in 2009. The primary reasons for the projected increase from 2008 are that our major southwest Connecticut transmission projects will be fully reflected in rates in 2009 due to their completion in the second half of 2008 and that the 2008 Con Edison settlement payment is absent in 2009, partially offset by the payment in 2009 of major storm costs incurred in December 2008 that likely will not be fully recovered from customers in 2009. Excluding potential contributions to our pension plan, we currently project our internally-generated cash flows to grow to approximately $1 billion by 2013.
- As of February 25, 2009, we had approximately $466 million of externally invested cash. At this time, we also had approximately $51 million of borrowing availability on our revolving credit lines, excluding the remaining unfunded commitment of Lehman Brothers Commercial Bank (LBCB) (refer to "Liquidity - Impact of Financial Market Conditions" for further discussion).

Overview

Consolidated: We earned $260.8 million, or $1.67 per share, in 2008, compared with $246.5 million, or $1.59 per share, in 2007 and $470.6 million, or $3.05 per share, in 2006. Results for 2008 included an after-tax charge of $29.8 million, or $0.19 per share, resulting from the settlement of litigation with Con Edison. Excluding that charge, our earnings in 2008 were $290.6 million, or $1.86 per share. Results for 2006 included an 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 (Foundation) of $3 million and $25 million, respectively. There was no such contribution in 2008. A summary of our earnings, which also reconciles the non-GAAP measures of consolidated non-GAAP earnings and EPS, as well as EPS by segment, to the most directly comparable GAAP measures of consolidated net income and fully diluted EPS, for 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,					
	2008		2007		2006	
(Millions of Dollars, except per share amounts)						
	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net Income (GAAP)	$ 260.8	$ 1.67	$246.5	$ 1.59	$470.6	$3.05
Regulated companies	$ 289.1	$ 1.85	$228.7	$ 1.47	$183.3	$1.19
Competitive businesses	13.1	0.08	11.7	0.08	(102.7)	(0.66)
NU parent and other companies	(11.6)	(0.07)	6.1	0.04	2.0	0.01
Non-GAAP earnings	290.6	1.86	246.5	1.59	82.6	0.54
Con Edison litigation charge	(29.8)	(0.19)	-	-	-	-
Gain on sale of competitive business	-	-	-	-	314.0	2.03
Reduction in income tax expense (PLR)	-	-	-	-	74.0	0.48
Net Income (GAAP)	$ 260.8	$ 1.67	$246.5	$ 1.59	$470.6	$3.05

Regulated Companies: Our regulated companies segment their earnings between their electric transmission segments and their electric and gas distribution segments, with PSNH generation included in the electric distribution segment. A summary of regulated company earnings by segment for 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2008	2007	2006
CL&P Transmission*	$ 115.6	$ 66.7	$ 46.9
PSNH Transmission	16.7	10.7	8.3
WMECO Transmission	6.0	5.1	4.6
Total Transmission*	$ 138.3	$ 82.5	$ 59.8
CL&P Distribution*	$ 70.0	$ 61.4	$ 147.6
PSNH Distribution	41.4	43.7	27.0
WMECO Distribution	12.3	18.5	11.0
Yankee Gas	27.1	22.6	11.9
Total Distribution*	$ 150.8	$ 146.2	$ 197.5
Net Income - Regulated Companies*	$ 289.1	$ 228.7	$ 257.3

*After preferred dividends of CL&P in all years.

The higher 2008 and 2007 transmission segment earnings reflect a higher level of investment in this segment as we continued to build out our transmission infrastructure to meet the region's reliability needs. CL&P's transmission segment earnings increased primarily due to the investment by CL&P of approximately $1.6 billion since the beginning of 2005 in the southwest Connecticut transmission projects that were completed in 2008. At December 31, 2008, our transmission segment rate base was approximately $2.4 billion, compared with approximately $1.5 billion at December 31, 2007.

CL&P's 2008 distribution segment earnings were $8.6 million higher than 2007 primarily due to higher distribution revenues resulting from a distribution rate increase effective February 1, 2008, a settlement of federal tax matters, a lower effective income tax rate, and higher other revenues resulting from financial incentives under Connecticut's "Act

Concerning Energy Independence" to promote distributed generation and demand side management. These items were partially offset by a 3.7 percent decline in sales, higher operating costs, including full-year storm expenses, maintenance expenses, and interest expense, a $5.8 million pre-tax charge to refund the 2004 procurement incentive fee that was recognized in 2005 earnings, and losses on investments in the Trust Under Supplemental Executive Retirement Plan ("supplemental benefit trust"). CL&P's distribution segment Regulatory ROE was 7.5 percent in 2008 and 7.9 percent in 2007. We expect CL&P's distribution segment Regulatory ROE in 2009 will be approximately 7 percent.

PSNH's distribution segment earnings in 2008 were $2.3 million lower than 2007. The decrease in 2008 earnings was primarily due to higher operating costs including full-year storm expenses, depreciation, and interest expense, a 2.5 percent decline in sales, losses on the supplemental benefit trust and the absence of a $4.5 million pre-tax benefit from the implementation of the retail transmission cost tracking mechanism in the second quarter of 2007. These items were partially offset by an increase in PSNH's distribution revenues that resulted from distribution rate increases on July 1, 2007 and January 1, 2008, a pre-tax adjustment to its generation cost recovery mechanism of $1.9 million, and a settlement of federal tax matters. PSNH's distribution segment Regulatory ROE was 8.3 percent in 2008 and 9.5 percent in 2007. We expect PSNH's distribution segment Regulatory ROE in 2009 will be approximately 8 percent, with the earnings of the generation portion of this segment based on its authorized ROE of 9.8 percent.

WMECO's 2008 distribution segment earnings were $6.2 million lower than 2007 primarily due to higher operating costs, including full-year storm expenses, and uncollectibles expense, a 4.2 percent decline in sales, a $1.6 million pre-tax charge related to a DPU ruling on WMECO's 2005 and 2006 transition cost reconciliations, a $1.3 million pre-tax charge for potential refunds to customers from an assessment under the DPU's service quality index criteria, and losses on the supplemental benefit trust. These items were partially offset by a $3 million annualized distribution rate increase that took effect January 1, 2008 and a settlement of federal tax matters. WMECO's distribution segment Regulatory ROE was 7.2 percent in 2008 and 9.7 percent in 2007. We expect WMECO's distribution segment Regulatory ROE in 2009 will be approximately 8 percent.

Yankee Gas' earnings in 2008 were $4.5 million higher than 2007 primarily due to a distribution rate increase that took effect on July 1, 2007 and a 2.1 percent increase in firm natural gas sales. These increases were partially offset by higher operating costs, including uncollectibles expense, maintenance expense, and interest expense, and a DPUC order requiring Yankee Gas to refund $5.8 million of previous gas cost recoveries. Yankee Gas' Regulatory ROE was 8.3 percent in 2008 and 8.7 percent in 2007. We expect Yankee Gas' Regulatory ROE in 2009 will be approximately 9 percent.

For the distribution segment of our regulated companies, a summary of changes in CL&P, PSNH and WMECO retail electric KWH sales and Yankee Gas firm natural gas sales for 2008 as compared to 2007 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 Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage Decrease	Weather Normalized Percentage Decrease	Percentage (Decrease)/ Increase	Weather Normalized Percentage (Decrease)/ Increase
Residential	(4.1)%	(2.7)%	(2.2)%	(1.0)%	(3.1)%	(2.1)%	(3.6)%	(2.3)%	(2.0)%	(0.1)%
Commercial	(1.3)%	(0.7)%	(1.2)%	(0.4)%	(2.6)%	(2.1)%	(1.4)%	(0.8)%	(0.2)%	1.4 %
Industrial	(9.8)%	(9.3)%	(6.1)%	(5.4)%	(8.7)%	(8.5)%	(8.6)%	(8.1)%	9.2 %	9.6 %
Other	(3.2)%	(3.2)%	2.2 %	2.2 %	(14.6)%	(14.6)%	(3.7)%	(3.7)%	- %	- %
Total	(3.7)%	(2.8)%	(2.5)%	(1.6)%	(4.2)%	(3.5)%	(3.5)%	(2.6)%	2.1 %	3.4 %

A summary of our retail electric sales in gigawatt hours (GWH) for CL&P, PSNH and WMECO and firm natural gas sales in million cubic feet for Yankee Gas for 2008 and 2007 is as follows:

	Electric			Firm Natural Gas		
	2008	2007	Percentage Decrease	2008	2007	Percentage (Decrease)/ Increase
Residential	14,509	15,051	(3.6)%	13,467	13,742	(2.0)%
Commercial	14,885	15,103	(1.4)%	12,939	12,965	(0.2)%
Industrial	5,149	5,635	(8.6)%	13,310	12,193	9.2 %
Other	340	353	(3.7)%	-	-	- %
Total*	34,883	36,142	(3.5)%	39,717	38,900	2.1 %

**Amounts may not total due to rounding of GWH.*

Retail electric sales for 2008 were lower than 2007. The 2008 weather normalized decrease of 2.6 percent reflects the fact that our customers are responding to the increased costs of energy and to the adverse economic conditions of our region and the nation. We believe customers will continue to respond to these factors and to the recent disruptions and ongoing uncertainty in the financial markets, and have estimated a decline of approximately 1 percent in weather normalized electric sales in 2009, which is reflected in our earnings guidance. We experienced positive growth in our weather normalized electric sales of 1.3 percent for January 2009.

Changes in electric sales, however, have less of an impact on the earnings of the electric companies than in prior years because non-distribution rate revenues, which represented approximately 76 percent of electric company revenues in 2008, are tracked and reconciled to actual costs. Non-distribution rate revenues include the energy, stranded cost, retail transmission and federally mandated congestion costs (FMCC) charges and other components of rates. For non-distribution rate revenues, the only impact to earnings is from carrying costs on over- or underrecoveries. With respect to the distribution revenues, about two-thirds of CL&P's and WMECO's revenues and about one-half of PSNH's revenues are recovered through charges that are not dependent on overall sales volumes, such as the customer charge and the demand charge.

In addition to the manner in which the distribution rate revenues are recovered from customers, there are other reasons why changes in 2008 sales as compared to 2007 had less of an impact on our earnings. For example, some of the decline in 2008 industrial sales was due to qualified distributed generation in Connecticut replacing our distribution. Under Connecticut statute, CL&P is entitled to recover this lost distribution revenue through its FMCC charge. Also, some of the decline in 2008 commercial sales was attributable to certain generators who, in previous periods, took station service from CL&P as retail commercial customers but now are served directly by ISO-NE as wholesale customers. These customers are interconnected to the transmission system and do not contribute to distribution revenues, therefore the loss of load from these customers in 2008 did not impact our earnings.

Firm natural gas sales in 2008 were higher than 2007. The 2008 results reflect warmer weather in the first quarter, colder weather in the fourth quarter and an increase in industrial sales primarily due to customer-owned gas-fired distributed generation and favorable natural gas prices relative to oil. Similar to our electric distribution companies, Yankee Gas recovers a significant portion of its distribution revenues, approximately 40 percent, through charges that are not dependent on usage. Our 2009 earnings guidance reflects an estimated increase in weather normalized firm gas sales of approximately 2.5 percent.

Consistent with our sales results in 2008, our uncollectibles expense has also been influenced by the adverse economic conditions of our region. Our write-offs as a percentage of revenues increased in 2008 for all our distribution companies. Similar to changes in our retail sales, changes in our uncollectibles expense have less of an impact on earnings of our distribution companies than in prior years. For example, a portion of the uncollectibles expense for each of the electric distribution companies is allocated to its respective energy supply rate and recovered as a tracked expense. CL&P, PSNH and WMECO implemented their trackers for this allocated portion of uncollectibles expense on February 1, 2008, July 1, 2007, and January 1, 2007, respectively. Additionally, for CL&P and Yankee Gas, write-offs attributable to hardship customers are tracked and fully recovered in the System Benefits Charge (SBC) as uncollectible expense and in the base distribution rate as amortization expense, respectively. In 2008, our total uncollectibles expense was approximately $75 million or $25 million higher than 2007. Over $13 million of the increase was attributable to hardship accounts at CL&P. From a nontracked uncollectibles expense perspective, the 2008 expense was approximately $9 million greater than we originally expected. In 2009, we expect our total uncollectibles expense will be slightly higher than 2008 and the nontracked portion of uncollectibles expense to increase to approximately $30 million in 2009. This anticipated increase of 10 percent or $3 million is reflected in our 2009 earnings guidance.

Competitive Businesses: NU Enterprises, which continues to manage to completion its remaining wholesale marketing contracts and manages its energy services activities, earned $13.1 million in 2008, or $0.08 per share, compared with earnings of $11.7 million in 2007, or $0.08 per share, and $211.3 million, or $1.37 per share, in 2006. The 2008 results include a net after-tax reduction of earnings of $3.2 million associated with the implementation of Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurements." Competitive business earnings in 2008 also included positive mark-to-market after-tax results of $4.3 million associated with Select Energy, Inc.'s (Select Energy) wholesale marketing contracts, as compared to negative mark-to-market after-tax results of $3.8 million in 2007. The higher competitive business earnings in 2006 were attributable to the $314 million after-tax gain on the sale of the competitive generation business, partially offset by $70.3 million of losses at the retail marketing business, which was sold on June 1, 2006.

NU Parent and Other Companies: NU parent and other companies recorded net expenses of $41.4 million, or $0.26 per share, in 2008, compared with net income of $6.1 million, or $0.04 per share, in 2007, and net income of $2 million, or $0.01 per share, in 2006. The net expenses in 2008 primarily relate to the payment by NU parent to Con Edison of $49.5 million in March 2008 as part of a comprehensive settlement of litigation initiated in 2001 over the proposed but unconsummated merger between the two companies. The decrease in net income from 2007 was also the result of reduced interest income for NU parent on a significantly lower level of cash in 2008. NU parent carried a high level of cash in the first quarter of 2007 after the sale of our competitive generation businesses on November 1, 2006. Most of that cash was either invested in the regulated companies in 2007 to support those companies' capital programs or used to pay taxes due in March 2007 on the competitive generation business sales. Additionally, NU parent interest expense increased in 2008 due to the replacement of $150 million of 3.3 percent senior notes that matured on June 1, 2008 with $250 million of 5.65 percent senior notes.

Future Outlook

Earnings Guidance: A summary of our projected 2009 EPS by segment, which also reconciles consolidated fully diluted EPS to the non-GAAP measure of EPS by segment, is as follows:

	2009 EPS Range	
(Approximate amounts)	**Low**	**High**
Fully Diluted EPS (GAAP)	$ 1.80	$2.00
Regulated companies:		
Distribution segment	$ 1.00	$1.10
Transmission segment	0.85	0.90
Total regulated companies	1.85	2.00
Competitive businesses	0.00	0.05
NU parent and other companies	(0.05)	(0.05)
Fully Diluted EPS (GAAP)	$ 1.80	$2.00

This projection assumes the issuance of between $250 million and $300 million of additional equity in mid-2009. Our distribution rates are based in part on historic operation and maintenance costs, including pension and other postretirement costs and uncollectible expense. Primarily as a result of a significant decline in our pension assets due to current financial market conditions, we expect that higher pension costs will result in a $0.10 per share negative impact on earnings in 2009, as compared with 2008. The distribution segment earnings forecast noted above reflects our expectations of lower electric sales and higher pension and uncollectible expense than what we experienced in 2008.

Long-Term Growth Rate: We project that we will achieve an average compounded annual EPS growth rate of between 8 percent and 11 percent over 2007 EPS of $1.59 through 2013. Based on current economic conditions, we believe we will likely be at the lower end of this range. This EPS growth rate assumes achieved Regulatory ROEs of approximately 12 percent for transmission, between 9.5 percent and 10 percent for generation and between 9 percent and 9.5 percent for distribution investments. We believe this growth will be achieved if our capital program is successfully deployed according to our plans, distribution rate cases are approved to earn reasonable Regulatory ROEs and FERC's present transmission policies remain consistent and enable us to achieve projected transmission ROEs.

Business Development and Capital Expenditures

Consolidated: Our consolidated capital expenditures, including amounts incurred but not paid, cost of removal, allowance for funds used during construction (AFUDC), and the capitalized portions of pension and PBOP expense or income (all of which are non-cash factors in determining rate base), totaled $1.3 billion in both 2008 and 2007 and $945.8 million in 2006. These amounts include $33.2 million, $16 million and $17.6 million in 2008, 2007 and 2006, respectively, that related to our corporate service company and other affiliated companies that support the regulated companies.

Regulated Companies: We project making up to approximately $7 billion in capital investments for the regulated companies from 2009 through 2013. This projection includes capital expenditures of approximately $525 million for our portion of the costs associated with the new transmission initiative with NSTAR and HQUS, and approximately $150 million for our corporate service companies supporting the regulated companies. Given current financial conditions, we continue to carefully examine each investment to assess customer benefits, shareholder benefits and the ability to raise necessary capital.

A summary of our projected capital expenditures for 2009 through 2013 is as follows:

	Year					
(Millions of Dollars)	2009	2010	2011	2012	2013	2009-2013 Totals
CL&P Transmission	$ 97	$ 128	$ 267	$ 322	$ 160	$ 974
PSNH Transmission	58	177	400	273	154	1,062
WMECO Transmission	70	121	308	306	83	888
Other Transmission	-	20	95	205	205	525
Totals - Transmission	225	446	1,070	1,106	602	3,449
CL&P Distribution	278	352	338	309	311	1,588
PSNH Distribution	96	115	117	114	117	559
WMECO Distribution	30	38	33	33	34	168
Totals - Electric Distribution	404	505	488	456	462	2,315
PSNH Generation	156	199	144	83	41	623
Yankee Gas Distribution	66	90	92	74	77	399
Corporate service companies	70	34	21	13	12	150
Totals	$ 921	$1,274	$ 1,815	$ 1,732	$ 1,194	$ 6,936

Actual capital expenditures could vary from the projected amounts for the companies and periods above. Based on those estimated expenditures, projected transmission, distribution and generation rate base at December 31 of each year are as follows:

	Year				
(Millions of Dollars)	2009	2010	2011	2012	2013
CL&P Transmission	$2,024	$2,033	$2,224	$ 2,433	$ 2,454
PSNH Transmission	314	325	666	1,089	1,189
WMECO Transmission	125	218	488	729	876
Other Transmission	-	-	-	-	525
Totals - Transmission	2,463	2,576	3,378	4,251	5,044
CL&P Distribution	2,351	2,557	2,724	2,851	2,971
PSNH Distribution	774	865	954	1,042	1,095
WMECO Distribution	410	434	455	478	497
Totals - Electric Distribution	3,535	3,856	4,133	4,371	4,563
PSNH Generation	389	394	404	876	872
Yankee Gas Distribution	712	739	793	851	890
Totals	$7,099	$7,565	$8,708	$10,349	$11,369

The projected capital expenditures and rate base amounts reflected above assume that PSNH's Clean Air Project will be completed by the end of 2012 at a cost of $457 million. They also assume that $1.49 billion in transmission projects associated with NEEWS will be completed before the end of 2013. Numerous factors, some of which are beyond our control, may impact the regulated companies' rate base amounts above, including the level and timing of capital expenditures and plant placed in service and regulatory approvals.

Transmission Segment: Transmission segment capital expenditures decreased by $47.5 million in 2008 as compared with 2007 primarily due to reduced expenditures at CL&P associated with its transmission system projects in southwest Connecticut. A summary of transmission segment capital expenditures by company in 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2008	2007	2006
CL&P	$586.3	$660.6	$415.6
PSNH	81.9	80.7	36.1
WMECO*	44.2	19.3	13.0
HWP*	1.9	1.2	0.8
Totals	$714.3	$761.8	$465.5

*Does not include the transfer of $4 million in transmission assets from Holyoke Water Power Company (HWP) and its subsidiary, Holyoke Power and Electric Company (HP&E), to WMECO in December 2008.

Of its $586.3 million in transmission capital expenditures in 2008, CL&P invested approximately $470 million to complete its $1.6 billion series of four major transmission projects in southwest Connecticut. The first of those projects, the 21-mile 345 kilovolt (KV)/115 KV overhead and underground transmission line between Bethel, Connecticut and Norwalk, Connecticut, was placed in service in 2006. The remaining three projects that entered service in 2008 are as follows:

- The 69-mile, 345 KV/115 KV transmission project from Middletown to Norwalk, Connecticut (Middletown-Norwalk) that was constructed jointly with UI. CL&P's portion of this project cost approximately $950 million, $100 million lower than the earlier estimate of $1.05 billion primarily due to a decrease in capitalized financing costs because of the earlier-than-expected in service date. Of the $950 million, approximately $334 million was capitalized in 2008. The 45-mile overhead section of the project entered service on August 28, 2008. The 24-mile underground section entered service on December 16, 2008.
- The two-cable, nine-mile, 115 KV underground transmission project between Norwalk and Stamford, Connecticut (Glenbrook Cables), which entered service ahead of schedule on November 11, 2008. This project cost approximately $239 million, which is $16 million higher than the previous estimate due to increased construction costs related to underground obstacles. Of the $239 million, approximately $102 million was capitalized in 2008.
- The 138 KV, 11-mile undersea transmission project between Norwalk, Connecticut and Northport-Long Island, New York (Long Island Replacement Cable), which was completed in September 2008. CL&P's 51 percent portion of the project with Long Island Power Authority is estimated to be approximately $78 million, which represents a $7 million increase over the previous estimate. Of the $78 million, approximately $33 million was capitalized in 2008.

In 2008, in addition to the approximately $470 million invested in the three projects noted above, CL&P, PSNH, WMECO and HWP invested approximately $244 million in other transmission projects.

In October 2008, we commenced state regulatory filings for our next series of major transmission projects, NEEWS. That series of projects involves our construction of new overhead 345 KV lines in Massachusetts and Connecticut as well as associated substation work and 115 KV rebuilds. One of the projects will connect to a new transmission line that National Grid USA plans to build in Rhode Island and Massachusetts. On September 24, 2008, the ISO-NE issued its final technical approval of the NEEWS projects, which was a precursor to the siting application process. We estimate that CL&P's and WMECO's total capital expenditures for these projects will be $1.49 billion through 2013. In 2008, CL&P and WMECO capitalized approximately $19.7 million and $23.2 million, respectively, in costs associated with NEEWS.

The first of the NEEWS projects, the Greater Springfield Reliability Project, which involves a 115 KV/345 KV line from Ludlow, Massachusetts to North Bloomfield, Connecticut, is the largest and most complicated project within NEEWS. This project is expected to cost approximately $714 million if built according to our preferred route and configuration. CL&P filed its application to build the Connecticut portion of the Greater Springfield Reliability Project with the Connecticut Siting Council (Siting Council) on October 20, 2008. WMECO filed its application to build its portion of the project with the Massachusetts Energy Facilities Siting Board on October 27, 2008. The Connecticut Energy Advisory Board is currently reviewing Connecticut-based generation, demand side management and other proposed alternatives to the Greater Springfield Reliability Project, which must be submitted to the Siting Council by March 19, 2009. The Siting Council has preliminarily set dates for hearings, public comments and site visits on the Connecticut portion of the project in the second quarter of 2009. If the overall project is approved in 2010 as expected, we currently expect to commence construction in late 2010 and place the project in service in 2013.

Our second major NEEWS project is the Interstate Reliability Project, which is being designed and built in coordination with National Grid USA. CL&P's share of this project includes an approximately 40-mile, 345 KV line from Lebanon, Connecticut to the Connecticut-Rhode Island border where it would connect with enhancements National Grid USA is designing. We expect CL&P's share of this project to cost approximately $250 million. Municipal consultations concluded in November 2008, and CL&P plans to file siting applications with Connecticut regulators by the third quarter of 2009 with construction beginning as early as late 2010. We currently expect the project to be placed in service as early as 2012.

The third part of NEEWS is the Central Connecticut Reliability Project, which involves construction of a new line from Bloomfield, Connecticut to Watertown, Connecticut. This line would provide another 345 KV connection to move power across the state of Connecticut. The timing of this project would be six to twelve months behind the other two projects, and CL&P currently expects to file the siting application in early 2010, with construction beginning in 2011. The project is currently expected to be placed in service in 2013 at a cost of approximately $315 million. Included as part of NEEWS are approximately $210 million of associated reliability related expenditures, some of which may be incurred in advance of the three major projects.

During the siting approval process, state regulators may require changes in configuration to address local concerns that could increase construction costs. Our current design for NEEWS does not contemplate any underground lines. Building any lines underground, particularly 345 KV lines, would increase total costs, and our estimate could be increased during the siting approval process.

On December 12, 2008, NU and NSTAR submitted a joint petition for a declaratory order to the FERC. The petition requests a ruling by the FERC that would allow NU and NSTAR to enter into a bilateral transmission services agreement with HQUS, a wholly-owned subsidiary of Hydro-Québec. Under such an agreement, NU and NSTAR would sell 1,200 MW of firm electric transmission service over a newly constructed, participant-funded transmission tie line connecting New England with the Hydro-Québec system in order for HQUS to sell and deliver into New England this same amount of firm electric power from Canadian low-carbon energy resources. If FERC issues the declaratory order as we anticipate, NU and NSTAR would subsequently seek approval from FERC of the specific terms and conditions of the transmission arrangement. NU, NSTAR and HQUS have signed memoranda of understanding to develop this transmission project on an exclusive basis. This project would provide a competitive source of low-carbon power that is favorable in comparison to current alternatives and would also provide for an expansion of New England's transmission system without raising regional transmission rates. NU, NSTAR and HQUS have also begun discussions on the specifics of a potential long-term power purchase agreement that would ensure the line is utilized to bring low-carbon power to benefit New England customers. A FERC order is expected in the first half of 2009, and if the order approves the proposal, then NU and NSTAR plan to negotiate a power purchase agreement with HQUS later in 2009. The terms of such agreement would be subject to regulatory approvals in several states.

Assuming completion of an acceptable power purchase agreement and receipt of all necessary state and federal regulatory approvals, we expect this project to be under construction between 2011 and 2014. Our portion of the costs of this project is currently estimated to be approximately $525 million. HQUS will reimburse NU and NSTAR for the total costs of this project, including an investment return to these companies, over the estimated 40-year operating life of the transmission line. NU and NSTAR's intent is to create an agreement that approximates a typical FERC approved cost-of-service rate structure. The revenue recovery model will ultimately require FERC approval.

Distribution Segment: A summary of distribution segment capital expenditures by company in 2008, 2007 and 2006 is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2008	2007	2006
CL&P	$296.6	$283.3	$210.3
PSNH	98.2	88.3	77.5
WMECO	37.8	34.0	30.0
Totals - Electric distribution (excluding generation)	432.6	405.6	317.8
Yankee Gas	44.0	63.7	89.9
Other	0.5	0.4	2.3
Total distribution	477.1	469.7	410.0
PSNH generation	74.0	35.3	32.1
Total distribution segment	$551.1	$505.0	$442.1

PSNH's Clean Air Project is expected to cost approximately $457 million, which will be recovered through its generation rates under New Hampshire law. PSNH commenced preliminary site work for this project in 2008. The project is scheduled to be completed by the end of 2012. As of December 31, 2008, PSNH had capitalized approximately $27.5 million associated with this project, of which $24.8 million was capitalized in 2008. Refer to "Regulatory Developments and Rate Matters - New Hampshire - Merrimack Clean Air Project" for further discussion, including the status of the New Hampshire Supreme Court proceedings and their effect on this project.

On February 15, 2008, Yankee Gas and NRG Energy, Inc. (NRG) entered into a settlement agreement, which, among other things, allowed for the recovery by Yankee Gas of approximately $17.5 million of capital costs and expenses related to an NRG subsidiary's generating plant construction project that was abandoned. The 2008 capital expenditures at Yankee Gas were offset by this $17.5 million recovery, and the 2007 capital expenditures included $12 million spent on its $108 million liquefied natural gas storage and production facility in Waterbury, Connecticut, which was placed in service in July 2007.

Liquidity

Consolidated: We had $89.8 million of cash and cash equivalents on hand at December 31, 2008, compared with $15.1 million at December 31, 2007. As of February 25, 2009, we had approximately $466 million of externally invested cash. Refer to "Impact of Financial Market Conditions" below for further discussion.

We had positive consolidated operating cash flows in 2008 of $418.5 million, after RRB payments included in financing activities, compared with negative operating cash flows of $11.3 million in 2007 and positive operating cash flows of $233.7 million in 2006, both after RRB payments. The increase in 2008 operating cash flows was primarily due to the absence in 2008 of approximately $400 million in tax payments in 2007 related to the 2006 sale of the competitive generation business, partially offset by the litigation settlement payment to Con Edison of $49.5 million in 2008. After factoring these cash flow impacts, the increase in operating cash flows in 2008 from 2007 was primarily due to a favorable impact of approximately $118 million from tax-related matters in 2008, which included an income tax net settlement of approximately $78 million in the fourth quarter and a reduction in income tax payments of approximately $40 million during 2008 related to bonus depreciation. The cash flow benefit of our accounts payable balances increased by $122 million, excluding approximately $50 million in unpaid costs at PSNH related to a major storm in December 2008 that are deferred and expected to be recovered from customers or insurance proceeds. These factors were partially offset by a net reduction in other working capital items resulting primarily from a net $136 million increase in accounts receivable and unbilled revenues items, which also included investments in securitizable assets.

We project consolidated operating cash flows of approximately $500 million in 2009, after RRB payments of $244 million, which represents an increase of approximately $82 million, or 19 percent, from 2008 operating cash flows, after RRB payments. This projected increase does not include any pension plan contributions, as they are not required to be paid during 2009, and is primarily due to our major southwest Connecticut transmission projects being fully reflected in rates in 2009 after their completion in the second half of 2008 and the absence in 2009 of the Con Edison settlement payment. These factors are partially offset by the payment in 2009 of major storm costs incurred in December 2008 that likely will not be fully recovered from customers in 2009. Excluding potential contributions to our Pension Plan, we currently project our internally-generated cash flows to grow to approximately $1 billion by 2013 due to our cash return on and recovery of capital investment program expenditures.

In 2008, NU parent, CL&P, PSNH and Yankee Gas issued a total of $760 million of long-term debt. On May 27, 2008, CL&P sold $300 million of first and refunding mortgage bonds due May 1, 2018 and carrying a coupon of 5.65 percent and PSNH sold $110 million of first mortgage bonds due May 1, 2018 and carrying a coupon of 6 percent. Proceeds from the CL&P and PSNH issuances were used to repay short-term debt, to fund each company's ongoing capital investment programs, and for general working capital purposes. On June 5, 2008, NU parent sold $250 million of senior unsecured notes due June 1, 2013 and carrying a coupon of 5.65 percent. Most of the proceeds were used to repay $150 million of 3.3 percent notes that matured June 1, 2008. The balance of NU parent's debt issuance was used to pay down short-term debt, a portion of which was incurred in March 2008 as a result of the $49.5 million litigation settlement payment to Con Edison. On October 7, 2008, Yankee Gas sold $100 million of privately placed first mortgage bonds due October 1, 2018 and carrying a coupon of 6.9 percent. Yankee Gas used the proceeds to repay its borrowings under the regulated companies' credit facility, to fund capital investment programs and for general working capital purposes.

On February 13, 2009, CL&P issued $250 million of first and refunding mortgage bonds due February 1, 2019 and carrying a coupon of 5.5 percent. Proceeds from this issuance will be used to repay short-term debt and fund CL&P's capital investment program. In mid-2009 or earlier depending on market opportunities, we expect to issue $150 million of long-term debt at PSNH, subject to regulatory approval, and between $250 million and $300 million of additional equity. These issuances will be made primarily to repay short-term debt and fund our 2009 capital investment program, which will also be funded by available short-term borrowings and the projected growth in 2009 operating cash flows.

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's and WMECO's senior unsecured debt and CL&P's 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

On July 29, 2008, Moody's changed the outlook of Yankee Gas to stable from negative and affirmed the company's Baa2 corporate credit rating. On August 8, 2008, Fitch affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. In late

October 2008, S&P affirmed all of its ratings and outlooks on NU parent, CL&P, PSNH and WMECO. On November 5, 2008, S&P raised CL&P's unsecured debt rating to BBB from BBB- as a result of a comprehensive review of the unsecured ratings of United States investment grade utilities. S&P's ratings on CL&P's bonds and preferred stock were unaffected.

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, a number of Select Energy's supply contracts would require Select Energy to post additional collateral in the form of cash or letters of credit (LOCs). If such an event were to occur, Select Energy would, under its remaining contracts, be required to provide cash or LOCs in an aggregate amount of $23.2 million to various unaffiliated counterparties and cash or LOCs in the aggregate amount of $10 million to two independent system operators, in each case at December 31, 2008. NU parent would be able to provide that collateral. If unsecured debt ratings for CL&P or PSNH were to be reduced by either Moody's or S&P, a number of supply contracts would require CL&P and PSNH to post additional collateral in the form of cash or LOCs to various unaffiliated counterparties. If these ratings were to be reduced by one level, PSNH would be required to post collateral of $1 million as of December 31, 2008. If these ratings were to be reduced by two levels or below investment grade, the amount of collateral required to be posted by CL&P and PSNH would be $1.3 million and $24.5 million, respectively, at December 31, 2008. CL&P and PSNH would be able to provide these collateral amounts.

NU paid common dividends of $129.1 million in 2008, compared with $121 million in 2007 and $112.7 million in 2006. The increase in common dividends paid from 2006 to 2008 reflects a 7.1 percent increase in the amount of NU parent's common dividend that took effect in the third quarter of 2006, a 6.7 percent increase that took effect in the third quarter of 2007 and a 6.3 percent increase that took effect in the third quarter of 2008. On February 10, 2009, our Board of Trustees declared a common dividend of $0.2375 per share, payable on March 31, 2009 to shareholders of record as of March 1, 2009, which represents a $0.10 per share, or 11.8 percent, increase on an annual basis.

The February 2009 dividend declaration reflects our new policy, announced in November 2008, of targeting a dividend payout ratio of approximately 50 percent of earnings. Our goal is to continue increasing the dividend at a rate above industry average and to provide an attractive return to shareholders. In general, the regulated companies pay approximately 60 percent of their cash earnings to NU parent in the form of common dividends. In 2008, CL&P, PSNH, WMECO and Yankee Gas paid $106.5 million, $36.4 million, $39.7 million, and $31 million, respectively, in common dividends to NU parent. In 2008, NU parent contributed $210 million of equity to CL&P, $75.6 million to PSNH, $16.3 million to WMECO, and $20.8 million to Yankee Gas.

NU parent's ability to pay common dividends is subject to approval by its Board of Trustees and to NU's future earnings and cash flow requirements and is not regulated under the Federal Power Act but may be limited by certain state statutes, the leverage restrictions in its revolving credit agreement and the ability of its subsidiaries to pay common dividends. The Federal Power Act does, however, limit the payment of dividends by CL&P, PSNH and WMECO to their respective retained earnings balances unless a higher amount is approved by FERC, 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 the regulated companies. CL&P, PSNH, WMECO and Yankee Gas also are parties to a revolving credit agreement that imposes leverage restrictions.

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 on capital projects but not yet paid, cost of removal, the AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense or income. Our cash capital expenditures totaled $1.3 billion in 2008, compared with $1.1 billion in 2007 and $872.2 million in 2006. Our cash capital expenditures in 2008 included $849.5 million by CL&P, $238.9 million by PSNH, $78.3 million by WMECO, $58.3 million by Yankee Gas, and $30.4 million by other NU subsidiaries. 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. The increase in our aggregate cash capital expenditures was primarily the result of higher distribution segment capital expenditures.

NU Parent: NU parent has a credit line in a nominal aggregate amount of $500 million including the commitment of LBCB (as further discussed below), which expires on November 6, 2010. At December 31, 2008, NU parent had $87 million of LOCs issued for the benefit of certain subsidiaries (primarily PSNH) and $303.5 million of borrowings outstanding under this facility. The weighted-average interest rate on these short-term borrowings at December 31, 2008 was 3.35 percent, which is based on a variable rate plus an applicable margin based on our credit ratings. We had approximately $50 million of borrowing availability on this facility as of February 25, 2009, excluding LBCB's remaining unfunded commitment. We also had approximately $466 million of externally invested cash at February 25, 2009.

Regulated Companies: The regulated companies maintain a joint credit facility in a nominal aggregate amount of $400 million including the commitment of LBCB (as further discussed below), which expires on November 6, 2010. There were $315 million of borrowings outstanding under this facility at December 31, 2008. The weighted-average interest rate on these short-term borrowings at December 31, 2008 was 3.35 percent, which is based on a variable rate plus an applicable margin based on our credit ratings. We had approximately $1 million of borrowing availability on this facility as of February 25, 2009, excluding LBCB's remaining unfunded commitment. As stated above, we also had approximately $466 million of externally invested cash at February 25, 2009.

Prior to June 30, 2008, CL&P had an arrangement with CL&P Receivables Corporation (CRC), a consolidated wholly-owned subsidiary of CL&P, and a financial institution under which the financial institution could purchase up to $100 million of CL&P's accounts receivable and unbilled revenues from CRC. On June 30, 2008, CL&P chose to terminate the Receivables Purchase and Sale Agreement due to the availability and lower relative cost of other liquidity sources. At this time, we have no further plans to securitize the accounts receivable and unbilled revenues of our regulated companies and will utilize our credit facilities and other financing vehicles, as necessary, to fund the daily operating activities and capital programs of these companies.

Our debt agreements provide that NU and certain of its subsidiaries, including CL&P, PSNH and WMECO, must comply with certain financial and non-financial covenants as are customarily included in such agreements, including a consolidated debt to capitalization ratio. The parties to these agreements currently are and expect to remain in compliance with these covenants. Refer to Note 2, "Short-Term Debt," and Note 11, "Long-Term Debt," to our consolidated financial statements included in this annual report for further discussion of material terms and conditions of our outstanding debt agreements.

Impact of Financial Market Conditions: While the impact of continued market volatility and the extent and impacts of any economic downturn cannot be predicted, we currently believe that we have sufficient operating flexibility and access to funding sources to maintain adequate liquidity (as evidenced by CL&P's issuance of $250 million of 10-year bonds in February 2009 at 5.5 percent). The credit outlooks for NU parent and our regulated companies are all stable, with all their ratings and outlooks affirmed by S&P in late October 2008. Our companies have modest risk of calls for collateral due to our business model, as described further below. No cash contributions to our pension plan are required during 2009. We also have only $50 million of long-term debt maturing in 2009, and projected capital expenditures for

2009 are significantly less than 2008. In the fourth quarter of 2008, we announced a new common dividend policy that targets a payout ratio of approximately 50 percent of earnings. While this new policy may require additional cash to fund common dividends, the incremental cash increase is relatively small and we continue to have a modest payout ratio relative to peer companies.

We successfully completed our planned long-term debt financings in 2008, as well as a CL&P bond issuance in early 2009, and we continue to have access to our two revolving credit facilities described above in a nominal aggregate amount of $900 million. The lenders under these facilities are: Bank of America, N.A.; Barclays Bank PLC; BNY Mellon, N.A.; Citigroup Inc.; HSBC Bank USA, N.A.; JPMorgan Chase Bank, N.A.; LBCB; Sumitomo Mitsui Banking Corporation; Toronto Dominion (Texas) LLC; Union Bank of California, N.A.; Wachovia Bank, N.A.; and Wells Fargo Bank, N.A. Borrowing capacity under the facility has not been reduced as a result of the 2008 merger of Wachovia and Wells Fargo. Lehman Brothers Holdings Inc., the parent of LBCB, filed for Chapter 11 bankruptcy protection in September 2008. LBCB's original aggregate lending commitment under the facilities was $85 million, $30 million of which was assigned to Sumitomo Mitsui Banking Corporation in late September, at which time LBCB had advanced approximately $23.5 million under the facilities. LBCB subsequently declined to fund the remainder of its commitment. As a result, when current loans from LBCB are repaid, we will be limited to an aggregate of $845 million of borrowing capacity under our credit facilities, which we believe will provide sufficient operating flexibility to maintain adequate liquidity. We have no other exposure to Lehman Brothers Holdings Inc. or any of its affiliates. As of December 31, 2008, we had borrowings and LOCs outstanding of approximately $706 million under the credit facilities, and approximately $793 million as of February 25, 2009, including $19.2 million remaining outstanding from LBCB. As of February 25, 2009, we also had approximately $466 million of externally invested cash.

In addition to the revolving credit facilities described above, we intend to access the capital markets, as appropriate, to fund our capital projects or otherwise meet funding needs. The availability and cost of external financings, including our expected financings in 2009 described below, will be affected by our financial condition and the then-current financial market conditions. There can be no assurance that the cost or availability of future borrowings, if any, will not be impacted by recent or future capital market disruptions.

PSNH has outstanding $407.3 million of Pollution Control Revenue Bonds (PCRBs), one series of which, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this series of PCRBs has been held by remarketing agents as the result of failed auctions due to general market concerns. The interest rate on these PCRBs has been reset by formula under the applicable documents every 35 days and has ranged between 0.2 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for a current interest rate of 0.3 percent. We are not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents. In addition, CL&P has outstanding $423.9 million of PCRBs, one series of which, in the aggregate principal amount of $62 million, had a fixed interest rate for a five-year period that expired on September 30, 2008. As a result of poor liquidity in the tax-exempt market, CL&P chose to acquire this series of PCRBs on October 1, 2008. These PCRBs, which mature in 2031, have not been retired and are being held temporarily by CL&P in a flexible interest rate mode with one-day resets. CL&P expects to remarket the PCRBs when market conditions improve.

We project that our cash capital expenditures will be approximately $880 million in 2009, which is significantly less than 2008. We also project that cash flows from operations after RRB payments will increase by approximately $82 million from 2008 to 2009 due to our southwest Connecticut transmission projects being reflected fully in rates in 2009, lower refunds of the previous year's overcollections, a $20 million retail rate increase at CL&P, and the absence in 2009 of the 2008 Con Edison settlement. Also, only one series of our bonds matures prior to 2012, which is Yankee Gas' $50 million that mature in the second quarter of 2009. Due to these factors, we expect to require significantly less debt financing in 2009 than in 2008 (approximately $400 million, including the $250 million issued by CL&P in February 2009, compared to $760 million in 2008). We also continue to expect an equity issuance of approximately $250 million to $300 million in mid-2009 (or earlier depending on market opportunities). The proceeds from these financings would be primarily used to repay short-term borrowings and fund our capital programs. We will monitor market conditions to determine the appropriate timing and amount of further 2009 financings.

Our regulated standard offer type contracts do not require us to post collateral. The regulated companies continue to solicit bids on wholesale power contracts, the collateral terms of which we expect to be consistent with existing contracts. In other regulated contracts that do contain collateral posting requirements, the counterparties are generally exposed to us at this time, and these counterparties have been posting the necessary collateral when required. As of December 31, 2008, PSNH had posted $75 million in related collateral in the form of LOCs with counterparties, as compared to $14 million at December 31, 2007.

An affiliate of Constellation Energy Group, Inc. (Constellation), whose credit ratings were downgraded in 2008 due to liquidity and other concerns, provides energy under CL&P's standard offer contracts. As of December 31, 2008, CL&P is not exposed to Constellation in terms of credit risk, and Constellation is performing on specific contracts. In the event of Constellation's default, CL&P would be required to provide standard offer type services directly to customers until a substitute supplier could be arranged. Any additional costs incurred by CL&P in such a case would be recoverable from customers. If Constellation were to default under existing contracts within the next 12 months, CL&P could be required to temporarily post additional collateral of between $15 million and $25 million with ISO-NE based on forward market prices as of December 31, 2008.

Our collateral requirements for Select Energy's few remaining wholesale contracts are modest as we continue to wind down this business. Select Energy's largest remaining contract does not contain any collateral posting requirements. In addition, we have not experienced any significant performance difficulties with suppliers on Select Energy's remaining sourcing contracts. Select Energy is required to post collateral, primarily with its New York Mercantile Exchange (NYMEX) broker, based on the market prices and status of its sourcing contracts. As of December 31, 2008, Select Energy had posted $26.3 million in related collateral, as compared to $18.9 million at December 31, 2007. Refer to "NU Enterprises Contracts - Counterparty Credit Risk" in this Management's Discussion and Analysis for further discussion.

At December 31, 2007 our pension plan funded ratio (pension plan assets divided by the accumulated pension plan benefit obligation) was 123 percent. Our pension plan has historically been well funded, and we have not been required to make a contribution to the plan since 1991. Due to the negative financial market conditions experienced in 2008, the fair value of our pension plan assets dropped by approximately $900 million to $1.56 billion as of December 31, 2008, and our plan's funded ratio is now 76 percent. Based on this 2008 plan year valuation and unless there is a change in current funding requirements, we will be required to make an estimated pre-tax contribution to the plan of approximately $150 million to meet minimum funding requirements. This contribution would be paid just prior to the 2009 federal income tax return filing, which will likely occur in the third quarter of 2010. No cash contributions to the plan will be required to be made in 2009.

For the 2009 pension plan year, it is likely that we will also be required to make a pension plan contribution unless there is a change in current funding requirements or a very significant recovery in the financial markets. Also, assuming that the pension plan assets earn the long-term rate of return of 8.75 percent and discount rates remain

constant, we currently estimate that we could be required to make an additional pre-tax contribution for the 2009 plan year in 2010 of between $150 million and $200 million. Contributions for the 2009 plan year would be made quarterly beginning in the second quarter of 2010.
If significant contributions for 2009 or future pension plan years are required and there is no change in regulatory recovery mechanisms, then there will likely be an impact on the timing and amount of our future debt and equity financings. The majority of our pension expense is included in rates charged to customers of our regulated companies.

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 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, subject to FERC approval, oversees the efficient and competitive functioning of the regional wholesale power market and determines the portion of the costs of our major transmission facilities that 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 Schedule 21 - NU rate schedules to recover fees for 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 Schedule 21 - NU 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 100 percent of the CWIP that is included in rate base on the NEEWS projects discussed below. The Schedule 21 - NU 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 Schedule 21 - NU 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 customers. At December 31, 2008, the Schedule 21 - NU rates were in a total underrecovery position of $4.6 million, which will be collected from customers in mid-2009.

FERC ROE Decision: On March 24, 2008, the FERC issued a rehearing order confirming its initial decision setting the base ROE for transmission projects for the New England transmission owners. Including a final adjustment, the order provides a base ROE of 11.14 percent for the period beginning November 1, 2006. The order also affirmed FERC's earlier decision granting a 100 basis point adder for transmission projects that are part of the ISO-NE Regional System Plan and are completed and on line by December 31, 2008. In 2008, we added $6 million in transmission segment earnings related to this order. This order has been appealed to the D.C. Circuit Court of Appeals by numerous state regulators and consumer advocates. The Court has set a schedule for briefing to conclude by the end of the second quarter of 2009. No date has been set for arguments.

On May 16, 2008, CL&P filed an application with the FERC to receive ROE incentives for its Middletown-Norwalk project and to seek a waiver of the "completed and on line" date of December 31, 2008 to earn incentives, pursuant to the FERC's March 24, 2008 order on rehearing. Alternatively, we requested the FERC to find that this project met the nexus test requirements for incentives under FERC's guidelines for new projects, and requested an additional 50 basis point adder for advanced technology used in the project.

The FERC subsequently granted the waiver request and approved the 100 basis point incentive for the entire Middletown-Norwalk project. The FERC also found that the project met the nexus test and granted an additional 50 basis point adder for the advanced technology aspects of the 24-mile underground portion of the project, ordering us to file more details regarding the advanced technology. The 50 basis point adder results in a total ROE for the underground portion of the Middletown-Norwalk project of 13.1 percent, which represents the overall ROE limit established by the FERC. Certain state regulators and municipal utilities sought rehearing, which were denied by the FERC, and Connecticut state regulators have since taken an appeal to the D.C. Circuit Court of Appeals. A schedule for the appeal has not yet been set. The technology adder increases CL&P's annual earnings beginning in 2009 by approximately $0.9 million.

On August 18, 2008, CL&P made a compliance filing with the FERC detailing the costs associated with the underground cables and supporting facilities of the Middletown-Norwalk project, which qualified as advanced technology. On September 8, 2008, the DPUC filed a motion to reject and protest our compliance filing, stating we did not provide sufficient information. There is no specific deadline for the FERC to respond to this motion. Our response to the protest has been filed at the FERC.

NEEWS Incentives: On November 17, 2008, the FERC issued an order granting incentives and rate amendments to National Grid USA and us for the NEEWS projects. The approved incentives include:

- An ROE of 12.89 percent, representing an incentive of 125 basis points, 25 basis points lower than requested;
- 100 percent inclusion of prudently incurred CWIP in rate base; and
- Full recovery of prudently incurred costs if NEEWS, or any portion thereof, is cancelled as a result of factors beyond NU's or National Grid USA's control.

Our share of NEEWS is estimated to cost $1.49 billion, and we received incentives on a portion of the transmission upgrades with a current estimated cost to NU of $1.41 billion. Several parties have sought rehearing of the FERC order granting incentives for NEEWS, which have not yet been acted on by the FERC.

Legislative Matters

Environmental Legislation: The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by ten northeastern and mid-Atlantic states, including Connecticut, New Hampshire and Massachusetts, to develop a regional program for stabilizing and reducing carbon dioxide (CO2) emissions from fossil fuel-fired electric generating plants. RGGI proposes to stabilize CO2 emissions at 2009 levels and reduce them by 10 percent from these levels by 2018. RGGI is composed of individual CO2 budget trading programs in each of the participating states. Each participating state's CO2 budget trading program establishes its respective share of the regional cap, and each state will issue CO2 allowances in a number equivalent to its portion of the regional cap. Each CO2 allowance represents a permit to emit one ton of CO2 in a specific year. The RGGI states will distribute CO2 allowances primarily through regional auctions. Regulated power generators are able to purchase CO2 allowances issued by any of the participating states to demonstrate compliance with the RGGI program of the state governing their generating plants. Taken together, the individual participating state programs will function as a single regional compliance market for carbon emissions.

Connecticut adopted regulations in July 2008, which established an auction clearing price threshold of $5 per CO2 allowance, above which price all auction proceeds will be rebated to customers. For proceeds up to the clearing price threshold, 69.5 percent will be directed to the conservation and load management programs managed

by the state's utilities in conjunction with the Energy Conservation Management Board. Seventy-five percent of the RGGI auction proceeds directed to conservation and load management programs will be allocated to CL&P's programs. Because CL&P does not own any generating assets, it is not required to acquire CO2 allowances; however, CO2 allowance costs will likely be included in wholesale rates charged to CL&P in standard offer type contracts.

Massachusetts passed legislation in July 2008 that did not set an auction clearing price threshold for RGGI auctions. This law requires 80 percent of RGGI auction proceeds to be allocated to utility energy efficiency and demand response programs. Because WMECO does not own any generation assets, it is not required to acquire any CO2 allowances; however, CO2 allowance costs will likely be included in wholesale rates charged to WMECO in standard offer type contracts.

New Hampshire passed legislation in June 2008 that set an auction clearing price threshold of $6 per CO2 allowance in 2009, above which all auction proceeds will be rebated to customers. Proceeds below the threshold are to be used for demand response and energy efficiency programs.

The first regional auction of RGGI CO2 allowances took place on September 25, 2008. At the auction, more than 12.5 million CO2 allowances were sold at the clearing price of $3.07 per CO2 allowance. The second regional auction was held on December 17, 2008, and more than 31.5 million allowances were sold at a clearing price of $3.38 per CO2 allowance. Auctions are scheduled for March, June, September and December 2009.

PSNH anticipates that its generating units will emit between 4 million and 5 million tons of CO2 per year after taking into account the operation of PSNH's Northern Wood Power wood-burning generating plant, which under the RGGI formula, decreased PSNH's responsibility for reducing fossil-fired CO2 emissions by approximately 425,000 tons per year, or almost ten percent. New Hampshire legislation provides up to 2.5 million banked CO2 allowances per year for PSNH's fossil fueled generating plants during the 2009 to 2011 compliance period. These banked CO2 allowances will initially comprise approximately one-half of the yearly CO2 allowances required for PSNH's generating plants to comply with RGGI, and such banked allowances will decrease over time. PSNH expects to satisfy its remaining RGGI requirements by purchasing CO2 allowances at auction or in the market and has purchased allowances in the first two auctions. The cost of complying with RGGI requirements is recoverable from PSNH customers.

New Hampshire:
2008 Legislation: In July 2008, New Hampshire passed a law establishing a transmission commission responsible for developing a proposal to expand the electric transmission system in northern New Hampshire to encourage the development of new renewable generation sources. On December 1, 2008, the transmission commission submitted its progress report, which concluded that New Hampshire should continue to pursue the upgrade of transmission capacity in its northern region to allow development of its native renewable energy resources. Also, the transmission commission should continue to pursue both local and regional cost allocation issues related to the transmission expansion. The northern New Hampshire region has the potential for over 500 MW of new renewable resources. PSNH has included $130 million in its 2009 to 2013 capital plan for transmission upgrades in this region, which assumes that these projects are built and that a cost allocation solution can be agreed to by relevant parties.

In July 2008, New Hampshire passed a law authorizing rate recovery by electric public utilities of investments made in distributed energy resources up to 5 MW, such as renewable energy generation. The total investment is limited to resources having a capability equal to 6 percent of a distribution utility's peak load. PSNH has not yet included any distributed energy resource investment opportunities in its capital expenditure plans.

Massachusetts:
2008 Legislation: As referenced above, in July 2008, Massachusetts enacted "The Green Communities Act of 2007." Aimed at increasing energy efficiency (EE) and the use of renewable resources in the state, the Act contains many provisions important to the state's utilities. In addition to adopting RGGI requirements, the Act:

- Removes the cap on utility expenditures for EE and demand response (DR). Requires utilities to file three-year EE and DR plans with a newly created Energy Efficiency Council;
- Requires utilities to sign long-term contracts for renewable resources;
- Allows each utility to own and operate up to 50 MW of solar generation;
- Requires utilities to file a plan with the DPU for a smart grid pilot; and
- Increases penalties for failure to meet service quality standards from 2 percent of transmission and distribution revenues to 2.5 percent.

By April 30, 2009, WMECO is required to prepare a three-year EE and DR investment plan related to the cost of EE and DR programs established by the Act for review by the Energy Efficiency Council and, ultimately, the DPU. Under the Act, utilities are authorized to own up to 50 MW of solar generating facilities, if part of a DPU approved plan. WMECO filed a program with the DPU on February 12, 2009 providing for a three-phase program with DPU authorization prior to each phase. The initial phase calls for 6 MW to be installed at eight host sites in WMECO's service territory upon receipt of DPU approval. This phase of the project is expected to be completed as early as 2010 at a cost of approximately $42 million. The second phase includes an additional 9 MW extending through 2012, and the third and final phase could increase total capacity to the 50 MW maximum. The DPU has six months to issue a decision on WMECO's plan. WMECO is otherwise precluded from making new generation investments, but has not yet included any solar generation investment opportunities in its capital expenditure plans.

Corporate Excise Tax: On July 3, 2008, Massachusetts amended its corporate excise tax provisions, which are effective for tax years beginning on or after January 1, 2009. Companies must account for the impact of income tax law changes in the period that includes the enactment date of the law change. As a result, WMECO recorded an estimate of the impact of the new legislation as a $11.9 million decrease to deferred tax liabilities and a decrease to regulatory assets on its consolidated balance sheet as of December 31, 2008.

Regulatory Developments and Rate Matters

Regulated Distribution Companies: We are currently evaluating the rate case strategies of our distribution companies. Based on 2008 earnings, cost trends, sales trends and the impact of the December 11, 2008 ice storm, it is probable that PSNH will file a distribution rate case in 2009 seeking temporary rates effective by July 1, 2009, and permanent rates effective by July 1, 2010. CL&P has determined that it will not file a distribution rate case in mid-2009. CL&P will continue to consider the possibility of filing a rate case later in 2009 or in 2010, based on the economic, political and regulatory climate in Connecticut. In response to the July 2008 rate decoupling decision in Massachusetts, WMECO notified the DPU in September 2008 that it intends to file a distribution rate case seeking authority for full decoupling in mid-2010 to be effective in January 2011. We have no immediate plans to file a distribution rate case for Yankee Gas.

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, each of which recovers these costs through rates charged to their retail customers. Each of these companies has a retail transmission cost tracking mechanism as part of its rates, which allows them to charge their retail customers for transmission costs on a timely basis.

Forward Capacity Market: On December 1, 2006, a FERC-approved settlement agreement providing for an auction-based forward capacity market (FCM) mechanism was implemented and the payment of fixed compensation to

generators through May 31, 2010 began. The first forward capacity auction concluded in early February 2008 for the capacity year of June 2010 through May 2011. The bidding reached the established minimum of $4.50 per kilowatt-month with 2,047 MW of excess remaining capacity, which resulted in an effective capacity price of $4.25 per kilowatt-month compared to the previously established price of $4.10 per kilowatt-month for the capacity year preceding June 2010. The second auction concluded on December 10, 2008 for the capacity year of June 2011 through May 2012. The bidding reached the established minimum of $3.60 per kilowatt-month with 4,755 MW of excess remaining capacity, which resulted in an effective capacity price of $3.12 per kilowatt-month. These costs are recoverable in all jurisdictions through the currently established rate structures.

Connecticut - CL&P:
Distribution Rates: On January 28, 2008, the DPUC issued a final decision in a rate case CL&P filed on July 30, 2007. As a result of the decision, CL&P implemented a $77.8 million annualized distribution rate increase effective February 1, 2008 and an incremental $20.1 million annualized distribution rate increase effective February 1, 2009.

Peaking Generation Filing: In 2007, Connecticut passed "An Act Concerning Electricity and Energy Efficiency" (Energy Efficiency Act). Among other provisions, the Energy Efficiency Act required electric distribution companies, including CL&P, to file proposals with the DPUC to build cost-of-service peaking generation facilities. In 2008, the DPUC selected three projects, none of which were proposals submitted by CL&P, to provide peaking generation totaling approximately 500 MW. CL&P entered into CfDs with the developers of the three selected peaking generation units (Peaker CfDs). The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. As directed by the DPUC, CL&P and UI entered into a cost sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. CL&P's portion of the costs and benefits will be paid by or refunded to its customers.

Renewable Energy Contracts: In 2008, pursuant to Connecticut's "Act Concerning Energy Independence," (Energy Independence Act), CL&P signed five contracts, and UI signed two contracts each to purchase energy, capacity and renewable energy credits from planned renewable energy plants, including biomass and fuel cell projects approved by the DPUC, comprising a total of 109 MW of capacity. CL&P signed one contract with a biomass project in 2007 to purchase 15 MW of its output. Purchases under the contracts are scheduled to begin between 2009 and 2011 and will extend for periods ranging from 15 to 20 years. As directed by the DPUC, CL&P and UI have also signed a sharing agreement under which they will share the costs and benefits of these contracts, with 80 percent to CL&P and 20 percent to UI. On January 16, 2009, the DPUC issued a draft decision selecting two additional renewable energy projects for a total of 6 MW with which CL&P or UI will sign similar contracts. The DPUC's final decision on these projects is scheduled for March 11, 2009. Additional projects are expected to be selected by the DPUC to achieve a total of 150 MW of renewable energy sources in Connecticut in accordance with the Energy Independence Act. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

AMI Filing: On December 19, 2007, the DPUC issued a final decision on CL&P's compliance plan that requires a pilot program to test customer interest in, and response to, peak-time based rates and technical capabilities of an advanced metering infrastructure (AMI). On May 2, 2008, the DPUC approved CL&P's revised pilot plan, which was subsequently modified to provide for a summer 2009 rate pilot supported by meters for 3,000 voluntary rate pilot customers. The restriction of meters to only rate pilot participants decreased the required number of meters from 10,000 to the current 3,000. The rate pilot customer enrollment campaign began in November 2008. CL&P is required to submit a report on the customer response to the pilot, including technical capabilities of AMI meters and customer response to peak-time based rates by December 1, 2009. The estimated incremental cost of the program currently has a range of $10.6 million to $13 million. The incremental costs associated with the pilot are authorized to be recovered from customers, initially through CL&P's FMCC. The non-incremental costs are projected to be less than $2 million.

FMCC Filing: In September 2008, the DPUC approved CL&P's semi-annual FMCC filing, which reconciled actual FMCC revenues and charges (including Energy Independence Act charges), and generation service charge (GSC) revenues and expenses for the full year period January 1, 2007 through December 31, 2007, and that identified a total overrecovery of $105.4 million at December 31, 2007. The majority of this overrecovery was returned to customers in 2008 through credits included in 2008 rates that were determined in separate rate proceedings. On August 5, 2008, CL&P filed with the DPUC its semi-annual FMCC filing for the period January 1, 2008 through June 30, 2008. This filing identified a net overrecovery totaling $30.9 million including the remaining unamortized overrecovery from 2007. In December 2008, the DPUC issued a final decision covering this period that approved all costs as filed.

On February 6, 2009, CL&P filed with the DPUC its semi-annual FMCC filing for the year ended December 31, 2008, which identified an underrecovery totaling approximately $31.9 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet. A decision schedule has not yet been set at this time. We do not expect the outcome of the DPUC's review of this filing to have a material adverse effect on CL&P's net income, financial position or cash flows.

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. Effective January 1, 2009, the DPUC approved an increase to CL&P's total average SS rate of approximately 2.4 percent and a decrease to CL&P's total average LRS rate of approximately 5.9 percent. The energy supply portion of the total average SS rate increased from 11.852 cents per KWH to 12.316 cents per KWH. The energy supply portion of the total average LRS rate decreased from 12.667 cents per KWH to 11.738 cents per KWH. Effective April 1, 2009, the DPUC approved a decrease to CL&P's total average LRS rate of approximately 22 percent, which was a result of the energy supply portion decreasing to 8.207 cents per KWH from January 1, 2009. CL&P is fully and timely recovering the costs of its SS and LRS services.

CTA and SBC Reconciliation: On March 31, 2008, CL&P filed with the DPUC its 2007 Competitive Transition Assessment (CTA) and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying consolidated balance sheet. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet. On December 3, 2008, the DPUC issued a final decision in this docket that approved the 2007 CTA and SBC reconciliation with minor modifications. The decision referred to a potential change in the CTA rate effective January 1, 2009, when new rates were to be determined for all CL&P rate components. By letter dated December 23, 2008, the DPUC approved CL&P's recommendation to slightly decrease the base CTA rate and to establish a separate CTA refund credit beginning January 1, 2009. The CTA refund credit is intended to return to customers over a twelve month period a projected 2008 CTA overrecovery of $46.2 million, plus $1.8 million of incremental distribution revenues attributable to accelerating CL&P's previously allowed 2009 distribution rate increase from a start date of February 1, 2009 to January 1, 2009. The DPUC also approved an increase in the SBC rate to bill an additional

$11.7 million in 2009, which should enable CL&P to fully recover 2009 SBC expenses plus expenses that were underrecovered in prior periods.

Transmission Adjustment Clause: On June 16, 2008, CL&P filed a transmission adjustment clause (TAC) with the DPUC requesting an increase in its retail transmission rate effective July 1, 2008 to collect $67.9 million of additional revenues over the second half of the year. The increase in the TAC was attributable to the additional investment in regional transmission reliability projects. The DPUC approved CL&P's filing on June 25, 2008. On December 8, 2008, CL&P filed a TAC with the DPUC requesting no change to the retail transmission rate to be effective January 1, 2009, which covers the period January 1 through June 30, 2009. The DPUC approved CL&P's filing on December 23, 2008.

Procurement Fee Rate Proceedings: In prior years, CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its transition service procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. On January 15, 2009, the DPUC issued a final decision in this docket reversing its December 2005 draft decision and stated that CL&P was not eligible for the procurement incentive compensation for 2004. A $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers has been established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

Customer Service and Metering Dockets: In 2008, the DPUC issued final decisions in a docket examining the manner of operation and accuracy of CL&P's electric meters and in a docket investigating CL&P billing errors involving approximately 2,000 customers on time of use rates. In the metering docket the DPUC did not fine CL&P, but the metering decision held that possibility open if CL&P fails to meet benchmarks to be established in the docket. The decision in the time of use docket disallowed recovery from customers of the incremental costs associated either directly or indirectly with the billing errors. These incremental costs are not material and have been expensed as incurred.

2008 Management Audit: On August 18, 2008, a consulting firm hired by the DPUC began an on-site management audit of CL&P, which is required to be conducted every six years by statute and requires a diagnostic review of all functions of the company. The audit has been completed, and a final audit report is scheduled to be filed with the DPUC in the first quarter of 2009. We do not expect a material impact to CL&P's financial position or results of operations from results of this audit.

Connecticut-Yankee Gas:
Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas' PGA clause charges and required an audit of previously recovered PGA revenues of approximately $11 million associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund approximately $5.8 million in previous recoveries to its customers. The $5.8 million pre-tax charge (approximately $3.5 million net of tax) was recorded in the 2008 earnings of Yankee Gas.

New Hampshire:
Merrimack Clean Air Project: In 2006, the New Hampshire legislature enacted legislation requiring PSNH to reduce the mercury emissions from its coal-fired stations by at least 80 percent through the installation of wet scrubber technology at its Merrimack Station in Bow, New Hampshire no later than July 1, 2013. Following an August 2008 announcement by PSNH that the cost of this installation would be increasing from the original estimate of $250 million to $457 million, the New Hampshire Public Utilities Commission (NHPUC) opened an inquiry to determine its authority to find whether the project is in the public interest. On September 19, 2008, the NHPUC ruled that its authority is limited to determining at a later time the prudence of the costs of complying with the requirements of the scrubber legislation. In October 2008, several parties filed motions with the NHPUC requesting a reconsideration of its ruling. On November 12, 2008, the NHPUC issued an order denying the motions for rehearing. On December 11, 2008, several parties involved in the filing of the October 2008 motion for rehearing filed an appeal with the New Hampshire Supreme Court requesting that the Court overturn the NHPUC's finding that it lacked present authority over this matter. The Supreme Court has indicated that it will hear this appeal, but has not yet issued a schedule for oral arguments. PSNH has begun site work for this project and has capitalized approximately $27.5 million as of December 31, 2008. While PSNH does not expect the outcome of this appeal to adversely impact its ability to recover incurred costs from customers, should the Clean Air Act project be canceled for any reason, resulting contract cancellation payments and termination costs would likely amount to a substantial portion of the approximately $250 million of contractual commitments expected to be entered into by March 31, 2009. The actual total would depend on the timing of a cancellation, if it were to occur, and related negotiations with vendors.

Delivery Service Rates: On January 1, 2008, PSNH's distribution rates increased by approximately $3 million annually, pursuant to the NHPUC's May 2007 approval of PSNH's distribution and transmission rate case settlement agreement with NHPUC staff and the New Hampshire Office of Consumer Advocate. On July 1, 2008, PSNH's distribution rates decreased by $0.4 million annually. This amount consisted of a $3.4 million rate reduction related to the full recovery of a rate differential recoupment, offset by an annual increase of $3 million for additional funding of the Major Storm Costs Reserve (MSCR) for a two-year period effective July 1, 2008 to eliminate a negative balance in the MSCR and restore the intended reserve level of $1 million.

ES and SCRC Reconciliation and Rates: On May 1, 2008, PSNH filed its 2007 default energy service (ES) and stranded cost recovery charge (SCRC) reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation activities. During 2007, ES and SCRC revenues exceeded ES and SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a regulatory liability to be refunded to customers. On November 19, 2008, PSNH and the NHPUC Staff submitted a settlement agreement that resolved all outstanding issues. The NHPUC issued an order dated January 16, 2009 that accepted the settlement as filed. The settlement agreement and subsequent order did not have a material adverse impact on PSNH's financial position or results of operations. PSNH expects to file its 2008 ES and SCRC reconciliation with the NHPUC by May 1, 2009.
We do not expect the outcome of the NHPUC review to have a material adverse impact on PSNH's financial position or results of operations.

On June 27, 2008, the NHPUC issued orders increasing the ES rate from 8.82 cents per KWH to 9.57 cents per KWH and lowering the SCRC rate from 0.72 cents per KWH to 0.65 cents per KWH, effective from July 1, 2008 through December 31, 2008. In December 2008, the NHPUC issued orders that increased the ES rate to 9.92 cents per KWH and the SCRC rate to 0.98 cents per KWH. These rates will be effective from January 1, 2009 through December 31, 2009.

TCAM Reconciliation and Rates: On May 13, 2008, PSNH filed a July 1, 2007 through June 30, 2008 transmission cost adjustment mechanism (TCAM) reconciliation and a projected TCAM rate to be billed effective July 1, 2008 and continuing through June 30, 2009. Under the terms of an NHPUC rate order issued on June 27, 2008, PSNH's TCAM rate was increased from 0.752 cents per KWH to 0.935 cents per KWH, effective July 1, 2008.

Major Storm Costs Reserve: On December 11, 2008, a major ice storm struck portions of New England, severely damaging PSNH's distribution system. This was the most severe ice storm in PSNH's history. Of the 440,000 New Hampshire homes and businesses that lost power, 322,000 were served by PSNH. Restoration operations commenced on December 11, 2008 and were substantially completed

by December 25, 2008. PSNH utilized its own line crews, local contractors, line crews from other NU subsidiaries and numerous other line crews from the eastern United States and Canada.

The operating cost of storm restorations that meet a NHPUC specified criteria are funded through the MSCR. Capital costs for any storm work are charged to property, plant and equipment and recovered through the normal distribution ratemaking process. As the December 2008 ice storm met the MSCR criteria, $62.7 million of total estimated repair costs of $75 million associated with this storm were charged to the MSCR at December 31, 2008. PSNH intends to recover these costs as part of its next delivery rates proceeding with the NHPUC. Out of the remaining total storm costs incurred through December 31, 2008, $6.5 million of non-incremental costs has been expensed and $5.6 million has been capitalized to plant and equipment. PSNH expects to recognize an additional $10 million in 2009 when the weather is warmer and additional clean-up and repairs can be performed. We carry $15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to PSNH to reduce the amount of deferred or expensed storm costs. The NHPUC scheduled public hearings in March and April of 2009 as part of its review of state and utility operational responses to the storm. The costs of the December 11, 2008 storm did not have a material impact on PSNH's 2008 net income.

Renewable Portfolio Standards: On May 11, 2007, Governor Lynch signed into law the "Renewable Energy Act," establishing renewable portfolio standards (RPS) that requires annual increases in the percentage of electricity with direct ties to renewable sources sold to New Hampshire retail customers. The renewable sourcing requirements began in 2008 and increase each year to reach 23.8 percent in 2025. PSNH plans to meet these standards, in part, through the purchase of renewable energy certificates (RECs) from qualified renewable energy resources. For each MWH of energy produced from a qualifying resource, the producer will receive one REC. Energy suppliers, like PSNH, will purchase these RECs from the producers and will use them to satisfy the RPS requirements. To the extent that PSNH is unable to purchase sufficient RECs, it will be required to make up the difference between the RECs purchased and its total obligation by making an alternative compliance payment (ACP) for each REC requirement for which PSNH is deficient. The $8.7 million in 2008 costs for the RPS obligation did not impact earnings, as these costs are being recovered by PSNH through its ES rates.

Massachusetts:

Distribution Rates: On January 1, 2008, WMECO's distribution rates increased by $3 million annually as approved by the DPU in December 2006. WMECO adjusted its rates to include the distribution increase, new basic service contracts, and changes in several tracking mechanisms. On December 29 and 30, 2008, the DPU approved WMECO's proposed rate changes effective January 1, 2009. The rate changes were made in accordance with WMECO's various tracking mechanisms. The overall impact on customers' bills was a 0.5 percent increase for residential customers, a 2 percent decrease for small commercial and industrial customers, and a 3 percent decrease for medium and large commercial and industrial customers.

Basic Service Rates: Effective July 1, 2008, the rates for basic service customers increased due to the rise in the cost of energy reflected in WMECO's basic service solicitations. Basic service rates for residential customers increased from 10.8 cents per KWH to 12.1 cents per KWH, small commercial and industrial customers increased from 11.5 cents per KWH to 12.8 cents per KWH and rates for medium and large commercial and industrial customers increased from 10.5 cents per KWH to 14.6 cents per KWH. Effective October 1, 2008, the rates for WMECO's medium and large commercial and industrial basic service customers decreased from 14.6 cents per KWH to 11.1 cents per KWH due to the decline in the cost of energy, as reflected in its basic service solicitations. Effective January 1, 2009, the rates for all basic service customers decreased due to the decline in the cost of energy, as reflected in WMECO's basic service solicitations. Basic service rates for residential customers decreased from 12.1 cents per KWH to 11.8 cents per KWH, small commercial and industrial customers decreased from 12.8 cents per KWH to 12.1 cents per KWH and rates for medium and large commercial and industrial customers decreased from 11.1 cents per KWH to 10.2 cents per KWH.

Transition Cost Reconciliations: On June 20, 2008, the DPU issued its final decision on WMECO's 2005 and 2006 transition cost reconciliations, which resulted in a pre-tax charge of $1.6 million to WMECO's 2008 consolidated statements of income. The DPU ordered WMECO to use a ROE of 11 percent, and not the allowed ROE of 9.85 percent in 2005 and 2006, for purposes of calculating carrying cost credits for customers on the stranded cost deferrals. In addition, the DPU ordered WMECO not to combine certain overrecoveries and underrecoveries but instead to keep them separate and to calculate carrying costs on certain balances using a ROE of 11 percent and to use customer deposit rates on other balances. The impacts of this order on WMECO's calculations of the 2007 and year to date 2008 transition cost reconciliations were recorded in the second quarter of 2008.

Decoupling Decision: On July 16, 2008, the DPU issued a decision in its decoupling generic docket requiring all gas and electric utilities to file full decoupling proposals with their next general rate case. The decision rejected calls for partial decoupling or decoupling by rate design in favor of full decoupling by rate class. Actual revenues are to be reconciled to target revenues, as established in litigated rate cases, on an annual basis. Adjustments per the reconciliation will be made to the distribution component of rates. The decision also determined that the DPU will honor existing long-term rate plans, performance-based regulation plans and settlements. On September 2, 2008, WMECO notified the DPU that it expects to file its next distribution rate case in mid-2010 to be effective January 1, 2011. The distribution rate case will include a proposal to fully decouple distribution revenues from KWH sales.

Service Quality Performance Assessment: As part of the December 2006 rate case settlement agreement approved by the DPU, WMECO became subject to service quality (SQ) metrics that measure safety, reliability and customer service. Any charges incurred are paid to customers through a method approved by the DPU. WMECO will likely be required to pay an assessment charge for its 2008 reliability performance against the metrics established for 2008, primarily as a result of significant storm activity. WMECO has performed at target for other non-storm related reliability metrics. WMECO will file its 2008 SQ results and assessment calculation with the DPU in March 2009. In 2008, WMECO recorded an estimated pre-tax charge and a regulatory liability of approximately $1.3 million for this assessment.

Storm Costs Reserve: The December 11, 2008 ice storm also impacted areas served by WMECO. As this storm met the storm costs reserve criteria approved in WMECO's last distribution rate case settlement, $11.3 million of the total $13.8 million estimated repair costs associated with this storm were recognized as a deferred asset at December 31, 2008. WMECO expects to begin recovery of these costs in its next distribution rate proceeding. Out of the remaining total storm costs, $1.4 million has been expensed, including a significant portion of non-incremental costs, and $1.1 million has been capitalized to plant and equipment. We carry $15 million of storm-related insurance system-wide and to the extent that any insurance proceeds are received, a portion would be allocated to WMECO to reduce the amount of deferred or expensed storm costs. The DPU has opened a formal docket to review storm restoration efforts by the state's utilities and held public hearings in February 2009. The costs of the December 11, 2008 storm did not have a material impact on the 2008 earnings of WMECO.

Transfer of Transmission Assets: On December 15, 2008, the FERC approved the transfer of $4 million in transmission related assets of our wholly owned subsidiaries' HWP and

HP&E to WMECO, which occurred on December 31, 2008. After certain routine regulatory filings, HWP and HP&E will no longer be FERC-regulated entities.

Contingent Matters:
The items summarized below contain contingencies that may have an impact on our net income, financial position or cash flows. See Note 7A, "Commitments and Contingencies - Regulatory Developments and Rate Matters," to the consolidated financial statements for further information regarding these matters.

- **Transition Cost Reconciliation:** On July 18, 2008, WMECO filed its 2007 transition cost (TC) reconciliation with the DPU, which compared TC revenue and revenue requirements. For the twelve months ended December 31, 2007, total TC revenues along with carrying charges exceeded TC revenue requirements by $2.6 million, which has been recorded as a regulatory liability on the accompanying consolidated balance sheets. A public hearing and procedural conference was held on November 20, 2008. On December 22, 2008, the Massachusetts Attorney General filed testimony on two topics: the deferred return and carrying charges on the Capital Project Scheduling List; and the recovery of Northeast Nuclear Company pension/postretirement benefits other than pension (PBOP) costs. WMECO filed rebuttal testimony on December 30, 2008. A hearing was held on January 29, 2009. The briefing period ended on February 26, 2009. There is no timeline for a DPU decision. We do not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's net income, financial position or cash flows.
- **C2 Prudency Audit:** Pursuant to the decision in CL&P's 2007 rate case, the DPUC has hired a consulting firm to perform a prudency audit of certain costs incurred in the implementation of a new customer service system (C2) at CL&P. The audit began on December 1, 2008 and will be ongoing through early 2009, with a final report to the DPUC due March 31, 2009. The DPUC has stated its intentions to open a docket to review the findings of the audit after completion. We continue to believe that our C2 expenses were prudent and will be recovered in rates.

Deferred Contractual Obligations

We have decommissioning and plant closure cost obligations to Connecticut Yankee Atomic Power Company (CYAPC), Yankee Atomic Electric Company (YAEC) and Maine Yankee Atomic Power Company (MYAPC) (Yankee Companies), which have each completed the physical decommissioning of their respective nuclear 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 subsidiaries. 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, 2008 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, YAEC and MYAPC are currently collecting amounts that we believe are adequate to recover the remaining decommissioning and closure cost estimates for their respective plants. We believe CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. 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. In December 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The Court of Appeals issued its decision on August 7, 2008, effectively agreeing with the trial court's findings as to the liability of the DOE but disagreeing with the method that the trial court used to calculate damages. The Court of Appeals vacated the decision and remanded the case for new findings consistent with its decision.

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. 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 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 manages its energy services activities.

Wholesale Marketing: During 2008 Select Energy continued to manage its remaining PJM power pool wholesale sales contract and its related supply contracts, which expired on May 31, 2008, and its long-term wholesale sales contract with the New York Municipal Power Agency (NYMPA), an agency comprised of municipalities, and related supply contracts, that expires in 2013. These contracts are derivatives that have been marked to market through earnings. In addition to the NYMPA-related contracts, Select Energy's only other long-term wholesale obligation is a non-derivative contract to purchase and operate 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.

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, which completed our obligation.

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

Energy Services: Most of NU Enterprises' energy services businesses were sold in 2005 and 2006. Certain other businesses were wound down in 2007 and we continue to wind down minimal activity at the other energy services businesses. However, we continue to own and manage one energy services business, E.S. Boulos Company (Boulos), which is an electrical contractor based in Maine.

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 7F, "Commitments and Contingencies - Guarantees and Indemnifications," to the consolidated financial statements for information regarding these items.

NU Enterprises Contracts

Wholesale Derivative Contracts: On January 1, 2008, we implemented SFAS No. 157. For further information on SFAS No. 157, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the consolidated financial statements, and the "Critical Accounting Policies and Estimates" section of this Management's Discussion and Analysis.

At December 31, 2008 and 2007, the fair value of NU Enterprises' wholesale derivative assets and derivative liabilities (through its subsidiary Select Energy), which are subject to mark-to-market accounting, are as follows:

(Millions of Dollars)	December 31, 2008	2007
Current wholesale derivative assets	$ -	$ 36.2
Long-term wholesale derivative assets	-	7.2
Current wholesale derivative liabilities	(14.5)	(64.9)
Long-term wholesale derivative liabilities	(49.4)	(72.5)
Portfolio position	$(63.9)	$(94.0)

Numerous factors could either positively or negatively affect the realization of the wholesale derivative net fair value amounts in cash. These factors include the volatility of commodity prices until the derivative contracts are exited or expire, 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, 2008 and 2007. A description of each method is as follows: 1) prices actively quoted primarily represent NYMEX 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 historical experience with intramonth price volatility and bilateral contract prices in illiquid periods. Currently, Select Energy also has a derivative contract for which a portion of the contract's fair value is determined based upon a model. The model utilizes natural gas prices and a heat rate conversion factor to determine off-peak electricity prices for one New York routinely quoted hub zone for 2013. For the balance of hub zones, broker quotes for electricity prices are generally available on-peak through 2013 and off-peak through 2012.

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.

The tables below disaggregate the estimated fair value of the wholesale derivative contracts. Valuations of individual contracts are broken into their component parts based upon prices actively quoted, prices provided by external sources and model-based amounts. Under SFAS No. 157, contracts are classified in their entirety according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, these contracts are classified as Level 3 under SFAS No. 157. At December 31, 2008 and 2007, the sources of the fair value of wholesale derivative contracts are included in the following tables:

(Millions of Dollars)	Fair Value of Wholesale Contracts at December 31, 2008			
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	$ (10.1)	$ (7.3)	$ (1.2)	$(18.6)
Prices provided by external sources	(2.7)	(21.2)	(10.0)	(33.9)
Model-based [1]	(1.7)	(6.7)	(3.0)	(11.4)
Totals	$ (14.5)	$ (35.2)	$(14.2)	$(63.9)

(1) The model-based amounts include the effects of implementing SFAS No. 157.

(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)

For the years ended December 31, 2008 and 2007, the changes in fair value of these derivative contracts are included in the table:

(Millions of Dollars)	Total Portfolio Fair Value 2008	2007
Fair value of wholesale contracts outstanding at the beginning of the year	$ (94.0)	$ (126.5)
Pre-tax effects of implementing SFAS No. 157 ($3.2 million after-tax) [1]	(6.1)	-
Contracts realized or otherwise settled during the year [2]	29.2	38.9
Change in unrealized gains/(losses) included in earnings	7.0	(6.4)
Fair value of wholesale contracts outstanding at the end of the year	$ (63.9)	$ (94.0)

(1) Pre-tax effect recorded in fuel, purchased and net interchange power on the consolidated statement of income.

(2) The 2008 amount includes purchases, issuances and settlements of $24.2 million and realized intra-month gains of $5 million.

For further information regarding Select Energy's derivative contracts, see Note 3, "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 in economic, regulatory or other conditions. At December 31, 2008, approximately 99 percent of Select Energy's counterparty credit exposure to wholesale counterparties was non-rated, and approximately one percent was collateralized. The bulk of the non-rated credit exposure is comprised of one counterparty, which is a non-rated public entity that we have assessed as creditworthy. To date, this counterparty has met all of its contractual obligations.

Off-Balance Sheet Arrangements

Letters of Credit: PSNH has LOCs posted as collateral with counterparties and ISO-NE. At December 31, 2008, PSNH had $85 million in LOCs outstanding. In addition, Select Energy has a $2 million LOC posted at December 31, 2008.

Competitive Businesses: We have various guarantees and indemnification obligations outstanding on behalf of former subsidiaries in connection with the exit from our competitive businesses. See Note 7F, "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 position or results of operations. Our management communicates to and discusses with our Audit Committee of the Board of Trustees 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 further discussions of these policies and estimates as well as other accounting policies, estimates and assumptions used in the preparation of our consolidated financial statements.

Accounting for Environmental Reserves: Environmental reserves are accrued when assessments indicate that 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 these liabilities based on the most likely action plan from a variety of available options, ranging from no action to establishing institutional controls, full site remediation and long-term monitoring. The estimates associated with each possible action plan are 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 estimates 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 revision 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 recorded on an undiscounted basis.

HWP, a subsidiary of NU, continues to evaluate additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial investigative and remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of December 31, 2008. The cumulative expense recorded to this reserve through December 31, 2008 was approximately $15.9 million, of which $13.9 million had been spent, leaving approximately $2 million in the reserve as of December 31, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, which share responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP's 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed and begun to implement plans for additional investigations in conformity with MA DEP's guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, we believe that the $2 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $2 million to $2.7 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2009.

There are many outcomes that could affect our estimates and require an increase to the reserve, or range of costs, and a reserve increase would be reflected as a charge to pre-tax earnings. However, we cannot reasonably estimate the range of additional investigation and remediation costs because they will depend on, among other things, the level and extent of the remaining tar that may be required to be remediated, 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. Further developments may require a material increase to this reserve.

HWP's share of the remediation costs related to this site is not recoverable from customers.

Fair Value Measurements: We adopted SFAS No. 157 as of January 1, 2008. SFAS No. 157 defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). It establishes a framework for measuring fair value, using a three level hierarchy based upon the observability of inputs to the valuations. See Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the accompanying consolidated financial statements for further information.

As of January 1, 2008, we applied SFAS No. 157 to our regulated and unregulated companies' derivative contracts that are recorded at fair value and to the marketable securities held in our supplemental benefit trust and WMECO's spent nuclear fuel trust. We have also applied

SFAS No. 157 to valuations of investments in our pension and PBOP plans as of December 31, 2008. Implementing SFAS No. 157 for our marketable securities expanded our financial statement disclosures, but did not affect the recorded fair value of investments.

For the year ended December 31, 2008, we recorded a net after-tax reduction of earnings of $3.2 million as a result of applying SFAS No. 157 to derivative liabilities for Select Energy's remaining wholesale marketing contracts.

As a result of implementing SFAS No. 157, we also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers, and an offsetting regulatory asset or liability was recorded to reflect these changes. Implementing SFAS No. 157 resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets, of approximately $590 million and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million. The increase to CL&P's derivative liabilities primarily resulted from an increase in the negative fair value of a CfD with a generating plant to be built to reflect the estimated cost to exit this contract, reflecting an increase in the probability that the plant will be built and the recognition of a loss at the inception of the contract of approximately $100 million that was deferred under previous accounting guidance.

If we do not exit but rather serve out our derivative liability contracts, we will not make payments for some portion of the negative fair value recorded for the contracts. Likewise, we could receive more cash for derivative assets than the fair value recorded.

We use quoted market prices when available to determine fair values of financial instruments and classify those valuations as Level 1 within the fair value hierarchy.

If quoted market prices are not available, fair value is determined using quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments that are not active and model-derived valuations in which all significant inputs are observable. These valuations are classified as Level 2 within the fair value hierarchy.

Many of our derivative contracts that are recorded at fair value are classified as Level 3 within the hierarchy and are valued using models that incorporate both observable and unobservable inputs. Contracts valued using models are classified according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, an item may be classified as Level 3 even though there may be some significant inputs that are readily observable.

Contracts are valued using models when quoted prices in active markets for the same or similar instruments are not available. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. The observable inputs into the valuation include contract purchase prices and future energy prices for the near term. Discounted cash flow valuations incorporate estimates of premiums or discounts, reflecting risk adjusted profit that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit risk.

Changes in fair value of the remaining wholesale marketing contracts of our unregulated businesses are recorded in fuel, purchased and net interchange power on the accompanying consolidated statements of income. For the year ended December 31, 2008, there were net unrealized gains of $4.3 million ($7 million pre-tax), related to the valuation of these contracts. There were net realized gains of $3 million ($5 million pre-tax) for the year ended December 31, 2008. Key drivers of variability in fair values include changes in energy prices and expected volumes under the contracts. We utilize judgments in estimated expected volumes that are dependent on a number of factors including options exercised, customer utilization, weather and availability of other power sources to our counterparty. The valuations of our derivative contracts are highly sensitive to changes in market prices of commodities.

Changes in fair value of the regulated company derivative contracts are recorded as regulatory assets or liabilities, as we expect to recover these costs in rates. These valuations are sensitive to the prices of energy and energy related products in future years for which markets have not yet developed. Assumptions made to implement SFAS No. 157 had a significant effect on derivative values, and changes in assumptions may continue to have significant effects.

Total Level 3 derivative assets were 66 percent of our total assets measured at fair value, and Level 3 derivative liabilities were 91 percent of our total liabilities measured at fair value at December 31, 2008. A significant portion of our Level 3 derivative liabilities relate to the regulated company derivative contracts for which changes in fair value do not affect our earnings due to our use of regulatory accounting. Changes in fair value of these contracts are not material to our liquidity or capital resources because the costs and benefits of the contracts are recoverable from or refundable to customers on a timely basis.

Our regulated and unregulated business activities that result in the recognition of derivative assets create exposures to credit risk of energy marketing and trading counterparties. At December 31, 2008, we had $273.2 million of regulated company and NU parent derivative assets that are contracted with multiple entities, of which $125.5 million is contracted with investment grade entities, $4.6 million is contracted with a government-backed entity, $131.4 million is contracted with a non-rated subsidiary of an investment grade company and the remainder are contracted with multiple other counterparties. We consider the credit ratings of these companies in our valuation of derivative assets and we use published probability of default indices based on the credit ratings of the counterparties to discount the value of the derivative asset. Changes in our counterparties' credit impact our ability to collect the derivative asset. Our derivative assets are primarily related to our regulated companies. Credit losses on regulated company contracts would not affect our earnings because these entities are cost-of-service regulated companies and costs of these contracts are recoverable from our customers. In addition, we consider our own credit rating in the valuation of derivative liabilities. Adjusting our unregulated derivative liabilities to incorporate our credit risk had an after-tax impact of $0.7 million on the fair value of our derivative liability and net income for the year ended December 31, 2008. Our regulated companies derivative assets and liabilities were also reduced to reflect the impact of our counterparties' credit risk and our own credit risk on fair values, with no effect on net income.

NU has a policy of margining counterparties in the event that the fair value of a derivative contract exceeds a pre-determined threshold. Depending on the credit rating of the counterparty, an unsecured credit line is granted to counterparties. In the event the fair value exceeds the unsecured credit line, NU requires cash collateral for those open positions. There are exceptions to this policy for contracts whose terms are determined by regulators.

We review and update our fair value hierarchy classifications on a quarterly basis. As of December 31, 2008, we hold $53.5 million of investment securities in our supplemental benefit trust for non-pension retirement benefits and $55.7 million of investment securities in our WMECO spent nuclear fuel trust. These investments are classified in Levels 1 and 2. Classification of an investment security or group of investment securities into Level 3 may occur if a significant amount of inputs to their valuation is no longer observable due to a decline in market activity or liquidity. We have assessed the impact of recently increasing market illiquidity on the valuation of our investments. Observable inputs remain available to value

the classes of securities we own. We continue to monitor the liquidity of our securities and review our valuations to ensure proper classification within the fair value hierarchy.

We consider unrealized losses on investment securities in the trusts to be other than temporary by nature and recognize them as realized losses because investment decisions are made by our trustee and we do not have the ability to hold securities until unrealized losses are recovered. Therefore, unrealized losses incurred on our supplemental benefit trust are recorded as realized losses in our consolidated statements of income. In 2008, we recorded $9.2 million of after-tax unrealized losses incurred on our supplemental benefit trust in other income, net on the consolidated statement of income. These amounts were partially offset by $0.4 million of after-tax net realized gains on sales of investment securities. Losses related to the WMECO spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel obligation and do not impact earnings.

We believe that current market conditions were the key driver of losses recognized on our investment securities. As of December 31, 2008, our supplemental benefit trust invested in equity securities and investment grade fixed income securities (BBB- and above or equivalent). Our spent nuclear fuel trust invested in short-term investments and investment grade fixed income securities. We have $0.3 million of mortgage-backed and asset-backed securities collateralized by sub-prime debt or Alt-B debt held in the supplemental benefit trust and $0.2 million of mortgage-backed securities collateralized by Alt-A debt in the spent nuclear fuel trust. A significant portion of our mortgage-backed securities are U.S. Agency notes collateralized by residential mortgages. The underlying collateral of our corporate-asset backed securities includes residential home equity loans, auto and equipment loans, commercial mortgage-backed securities and credit card receivables.

For further information on derivative contracts and marketable securities, see Note 1E, "Summary of Significant Accounting Policies - Derivative Instruments," Note 3, "Derivative Instruments," and Note 9, "Marketable Securities," to the consolidated financial statements.

Pension and PBOP: Our subsidiaries participate in a uniform noncontributory defined benefit retirement plan (Pension Plan) covering substantially all our regular employees. In addition to the Pension Plan, we also participate in the 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 financial position or results of operations.

Pre-tax periodic pension expense for the Pension Plan was $2.4 million, $17.4 million and $52.7 million for the years ended December 31, 2008, 2007 and 2006, 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 $36.2 million, $38.4 million and $50.7 million for the years ended December 31, 2008, 2007 and 2006, 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 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 2008. 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	
	2008 and 2007		2008 and 2007	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:				
United States	40%	9.25%	55%	9.25%
Non-United States	17%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	2%	10.25%
Private	8%	14.25%	-	-
Debt Securities:				
Fixed income	25%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%
Real Estate	5%	7.50%	-	-

The actual asset allocations at December 31, 2008 and 2007 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 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," to the consolidated financial statements.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and postretirement 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 postretirement 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: Pension and PBOP expense consists of the service cost and prior service cost determined by our actuaries, the interest cost based on the discounting of the obligations and the amortization of the net transition obligation, offset by the expected return on plan assets. Pension and PBOP expense also includes amortization of actuarial gains and losses, which represent differences between assumptions and actual or updated information.

We calculate the expected return on plan assets by applying our assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This 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 calculated expected return and the actual return based on the change in the fair value of assets during the year. At December 31, 2008, total investment losses to be reflected in the four-year rolling average of plan assets over the next four years were $672.3 million and $73.9 million, for the Pension Plan and the PBOP Plan, respectively. As these asset losses are reflected in the average plan asset fair values, 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

approximately 12 years, which were the average future service period of the employees at December 31, 2008.

At December 31, 2008, the net actuarial loss subject to amortization over the next 12 years was $237.2 million and $104.9 million for the Pension Plan and PBOP Plan, respectively, which excludes the $672.3 million and $73.9 million of previous investment losses not currently reflected in the calculation of the fair value of Pension Plan and PBOP Plan assets, 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, 2008. 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 6.89 percent for the Pension Plan and 6.90 percent for the PBOP Plan at December 31, 2008. Discount rates used at December 31, 2007 were 6.60 percent for the Pension Plan and 6.35 percent for the PBOP Plan.

Forecasted Expenses and Expected Contributions: 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 forecasted expense for the Pension Plan and PBOP Plan will be $40.3 million and $37.3 million, respectively, in 2009, which is included in our guidance.

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. We expect to continue with our policy to contribute to the PBOP Plan at the amount of PBOP expense, excluding curtailments and special benefit amounts. Beginning in 2007, we made additional contributions to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amounted to $3.7 million in 2008 and is estimated to be $3.4 million in 2009.

We have not contributed to the Pension Plan since 1991. However, as discussed below, the fair value of Pension Plan assets declined significantly during 2008. This decline, and the resulting asset level compared to the Pension Plan obligation, resulted in a required pre-tax contribution for the 2008 Pension Plan year that we currently estimate to be $150 million (assuming there is no change in current funding requirements). This contribution would be made just prior to the filing of the 2009 federal income tax return, which will likely be filed in the third quarter of 2010.

For the 2009 pension plan year, it is likely that we will also be required to make a contribution unless there is a change in current funding requirements or a very significant recovery in the financial markets. Also assuming that the pension plan assets earn the long-term rate of return of 8.75 percent and discount rates remain constant, we could be required to make an additional pre-tax contribution for the 2009 plan year in 2010 of between $150 million and $200 million. Contributions for the 2009 plan year would be made quarterly starting in the second quarter of 2010.

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	2008	2007	2008	2007
Lower long-term rate of return	$ 11.8	$ 11.1	$ 1.3	$ 1.1
Lower discount rate	$ 11.6	$ 12.9	$ 1.4	$ 1.4
Lower compensation increase	$ (6.2)	$ (6.9)	N/A	N/A

Plan Assets: The fair value of the Pension Plan assets decreased by $902.6 million to $1.56 billion at December 31, 2008. This decrease includes benefit payments of $127.6 million in 2008. The Projected Benefit Obligation (PBO) for the Pension Plan increased by $40.8 million to $2.3 billion at December 31, 2008. These changes have changed the funded status of the Pension Plan on a PBO basis from an overfunded position of $202.5 million at December 31, 2007 to an underfunded position of $740.9 million at December 31, 2008. The PBO includes expectations of future employee compensation increases.

The accumulated benefit obligation (ABO) of the Pension Plan was approximately $490 million greater than Pension Plan assets at December 31, 2008 and approximately $454 million less than Pension Plan assets at December 31, 2007. The ABO is the obligation for employee service and compensation provided through December 31, 2008.

The value of PBOP Plan assets has decreased by $82.5 million to $195.6 million at December 31, 2008. The benefit obligation for the PBOP Plan has decreased by $23.6 million to $436 million at December 31, 2008. These changes have increased the underfunded status of the PBOP Plan on an accumulated projected benefit obligation basis from $181.5 million at December 31, 2007 to $240.4 million at December 31, 2008. We have made a contribution each year equal to the PBOP Plan's postretirement benefit cost, excluding curtailment and termination benefits.

The Pension Plan assets include certain investments that are not regularly priced in an active market. These investments include private equity interests and real estate fund assets, comprising approximately 15 percent of total plan assets as of December 31, 2008. In determining the fair value of Pension Plan assets as of December 31, 2008, we obtained the most recent financial statements and requested updated values as of December 31st from the fund managers in order to obtain the best possible estimate of fair values. For the private equity and many real estate funds, the fund managers were able to provide year-end estimates of value. After discussion with various fund managers, we obtained information about conditions in the real estate markets and concluded on appropriate real estate fund values where manager estimates had not been given. The valuation of these investments requires significant judgment. These values reflect management's best estimate as of December 31, 2008.

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 2008 and $1 million in 2007. Changes in the long-term health care cost trend assumption could have a material impact on our financial position or results of operations.

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. Management reviews triggering events as defined under SFAS No. 142 throughout the year and has determined that no triggering events occurred in 2008 that would have required interim testing before or after October 1st. 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 in the current period to the extent it is impaired.

We completed our impairment analysis as of October 1, 2008 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. We review the outcome of each of the approaches annually and weight them appropriately to determine the fair value of Yankee Gas. 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 ROE is calculated using risk-free rates, stock premiums and a beta representing Yankee Gas' volatility relative to the overall market. The discount rate fluctuates from year to year as it is based on external market conditions. In 2008, the discount rate decreased because the risk-free rate and the beta were much lower in 2008 than in 2007 due to the current market conditions and the stability of the natural gas industry in this market. 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 evaluations since adopting SFAS No. 142 have not resulted in impairment, the estimated fair value of Yankee Gas is sensitive to changes in assumptions. For example, if the risk adjusted discount rate increased from approximately 5.95 percent to approximately 6.52 percent or the merger multiple of comparable companies decreased from approximately 10.5 to approximately 9.7 and the weighting of our valuation methodologies remained the same, then the estimated fair value of Yankee Gas would be lower than its carrying value.

Income Taxes: Income tax expense is estimated annually for each of the jurisdictions in which we operate. This process involves estimating current and deferred income tax expense or benefit as impacted by earnings and the impact of temporary differences resulting from differing treatment of items, such as timing of the deduction and expenses, for tax and book accounting purposes, as well as, any impact of permanent differences resulting from tax credits, flow-through items, non-tax deductible expenses, etc. The temporary differences and flow-through items result in deferred tax assets and liabilities that are included in the consolidated balance sheets. The income tax estimation process impacts all of our segments. In accordance with the provisions of Accounting Principles Board (APB) No. 28, "Interim Financial Reporting," we record income tax expense quarterly using an estimated annualized effective tax rate. Adjustments to these estimates can significantly affect our consolidated financial statements.

Part of the annual process in making adjustments to these estimates, as needed, is a reconciliation of the actual tax positions and amounts included on our income tax returns as filed in the fall of each year for the previous tax year to the estimates or provisions made during the income tax estimation process described above. In the third quarter of 2008, the impact of these return to provision adjustments on income tax expense was a benefit of $3.2 million.

A reconciliation of expected tax expense at the statutory federal income tax rate to actual tax expense recorded is included in Note 1H, "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 previously filed in a tax return and income tax positions expected to be taken in a future tax return that have been reflected on our balance sheets. 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.

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: identification of derivatives and embedded derivatives, election and designation of the normal purchases and sales exception, identifying, electing and designating 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 financial statements.

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 fair value of derivative assets and liabilities with the same counterparty are offset as permitted under FIN 39, "Offsetting of Amounts Related to Certain Contracts - an Interpretation of APB Opinion No. 10 and FASB Statement No. 105." The actual experience on our derivative contracts as they are settled has not resulted in a material impact on earnings. For the year ended December 31, 2008, the realized gains on the wholesale derivative contracts of Select Energy at settlement date were $3 million ($5 million pre-tax).

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 prospectively.

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. The value of CfDs at December 31, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation that were recorded upon adoption of SFAS No. 157 on January 1, 2008. The changes in CfD values since inception were 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 that 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 generally 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 3, "Derivative Instruments," to the consolidated financial statements.

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 for which the customers have not yet been billed. Unbilled revenues are included in revenue on the statement of income 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 2008.

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."

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 1G, "Summary of Significant Accounting Policies - Regulatory Accounting," to the consolidated 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 (VIEs) for which we are the primary beneficiary as defined in FIN 46(R), "Consolidation of Variable Interest Entities." Determining whether we are the primary beneficiary of a VIE is complex and subjective, and requires our judgment. There are a variety of facts and circumstances and a number of variables taken into consideration to determine whether we are considered the primary beneficiary of a VIE. We need to determine whether the entity is a VIE and whether our interest in the entity is a variable interest. For each VIE in which we have determined we hold a variable interest, we perform a qualitative analysis that considers the nature of the VIE's risks and determine the variability created by these risks that the VIE is designed to create and pass along to its interest holders. We evaluate the degree to which the VIE is designed to pass along risks to NU or its subsidiaries. In addition, when considered necessary to identify the primary beneficiary of the VIE, we perform modeling of the potential results of the VIE under various scenarios to quantify the degree to which it passes variability to parties that hold variable interests, including NU or one of its subsidiaries. If the majority of the variability were determined to be passed along to us, then we would be required to consolidate that VIE. A change in facts and circumstances or a change in accounting guidance could require us to reconsider whether or not we are the primary beneficiary of the VIE.

The Energy Independence Act required the DPUC to consider the impact on distribution companies of entering into long-term contracts for capacity and 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, which included variable and fixed pricing elements. In 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 determined that this contract was a variable interest in a VIE. In 2008, CL&P and UI entered into seven additional long-term agreements with proposed renewable energy plants, of which four were determined to be variable interests in VIEs and the other three were concluded not to be variable interests because of their fixed pricing elements. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these contracts with 80 percent to CL&P and 20 percent to UI (cost sharing agreement). We utilized qualitative and quantitative analyses to evaluate whether entering into the renewable energy contracts and cost sharing agreement would require CL&P to consolidate the projects and determined that consolidation would not be required. The review of these contracts required significant management judgment and incorporated quantitative modeling of the projections of each plant under a variety of possible scenarios in order to determine the allocation of risk between variable interest holders including the developers, equity investors, financing institutions and CL&P. The primary variable factors considered in these analyses were the plants' operating performance and the projected market prices of energy, capacity and renewable energy credits.

In 2007, CL&P entered into two Capacity CfDs associated with the capacity of two generating projects to be built or modified, and UI entered into two capacity-related CfDs, one with a generating project to be built and one with a new demand response project. The contracts, referred to as Capacity 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. As directed by the DPUC, CL&P has a cost sharing agreement with UI under which it will share the costs and benefits of these four Capacity CfDs with 80 percent to CL&P and 20 percent to UI. We determined that the Capacity CfDs and the related cost sharing agreement are derivatives and that the projects do not require consolidation. Quantitative modeling was not required for these contracts because we concluded that the derivative contracts are not variable interests in the projects.

The Energy Efficiency Act required electric distribution companies, including CL&P, and allowed others to file proposals with the DPUC to build cost-of-service peaking generation facilities. In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by the DPUC (Peaker CfDs). As directed by the DPUC, CL&P and UI have entered into a cost sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these Peaker CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. Amounts paid or received under the Peaker CfDs will be recoverable from or refunded to customers. We used both qualitative and quantitative analyses to evaluate whether these contracts are variable interests in VIEs that require CL&P to consolidate the projects. CL&P determined that, while the contracts represent variable interests in VIEs, CL&P is not required to consolidate any of these projects as of December 31, 2008. For two of the projects, UI has an obligation to absorb 20 percent of the net costs or benefits of the projects through the cost sharing agreement and also holds ownership in the projects jointly with the developer. We concluded that UI is the party that is most closely associated with the VIEs due to its related party relationships with the projects and the cost sharing agreement. We performed quantitative modeling for these two projects and our qualitative analysis of UI's interests in the projects, which led us to conclude that CL&P is not required to consolidate these projects. The third peaker project is not currently held in a VIE. We utilized a quantitative model to determine the variability that CL&P would absorb if the project is transferred into a VIE and the Peaker CfD thus becomes a variable interest in a VIE. The primary variable factors considered in our quantitative analyses of the peaker projects were their projected capital costs, operating costs and operating performance as well as projected market revenues in the capacity markets. Based upon our quantitative analysis, we determined that the third project will likely require consolidation if in a future period it is transferred into a VIE. Consolidation of that project would not impact CL&P's net income, but could add approximately $140 million of plant, $85 million of nonrecourse debt and $55 million of equity (noncontrolling interest) to CL&P's balance sheet by the time the plant is placed in service (scheduled for June 2012). Any demonstrated increases in financing or other costs that might result from consolidation of the project would be recoverable from CL&P's customers.

The FASB is in the process of reinterpreting the consolidation requirements of FIN 46(R) and expects to issue revised guidance in the second quarter of 2009. If the proposed guidance were finalized in its current form, it would likely eliminate the requirement for consolidation when we do not have the power to direct matters that significantly impact the VIE's activities. CL&P would not likely be required to consolidate the peaker project if and when the new guidance becomes effective. The FASB reinterpretation of FIN 46(R), as drafted, would become effective on January 1, 2010. Changes in facts and circumstances and changes in accounting guidance resulting in reevaluation of the accounting treatment of these contracts could have a significant impact on the accompanying consolidated financial statements.

In December 2008, the FASB issued FASB Staff Position (FSP) FIN 46(R)-8, "Disclosures by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities," requiring additional disclosures about significant variable interests in variable interest entities (VIEs) effective for December 31, 2008 financial reporting. We do not have any significant variable interests in VIEs that would be required to be disclosed because our contracts do not materially impact our financial statements due to the pass-through to our customers of contract costs and benefits and because we are not currently the primary beneficiary of any VIE.

Other Matters

Consolidated Edison, Inc. Merger Litigation: On March 13, 2008, we entered into a settlement agreement with Con Edison, which settled all claims in the civil lawsuit between both parties relating to the proposed but unconsummated merger. Under the terms of the settlement agreement, we paid Con Edison $49.5 million on March 26, 2008, which resulted in an after-tax charge of $29.8 million. This amount is not recoverable from ratepayers.

Accounting Standards Issued But Not Yet Adopted:

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is effective January 1, 2009. SFAS No. 160 requires ownership interests in subsidiaries held by third parties (noncontrolling interests) to be presented within equity and clearly identified and labeled. It sets forth requirements for income statement presentation related to the activities of noncontrolling interests and for accounting for changes in ownership interests and provides guidance for deconsolidation. Implementation of SFAS No. 160 is not expected to have a material impact on our consolidated financial statements.

In June 2008, the FASB issued FASB Staff Position (FSP) EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities," which is effective January 1, 2009 and is required to be applied retrospectively. As a result of this FSP, our restricted stock awards that were not vested in 2007 and the first quarter of 2008 are considered participating securities in calculating EPS for these periods using the two-class method. Our restricted stock awards were completely vested during the first quarter of 2008 and are no longer awarded. FSP EITF 03-6-1 is not expected to impact our EPS for any period.

SFAS No. 157, which establishes a framework for identifying and measuring fair value, was issued in 2006 and applied in 2008 to the fair value measurements of financial assets and liabilities of NU and its subsidiaries. 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 is required to be applied

to nonrecurring fair value measurements of non-financial assets and liabilities beginning in 2009, including asset retirement obligations (ARO) and goodwill and other impairment analyses. Implementation of SFAS No. 157 to non-financial assets and liabilities is not expected to have a material impact on our consolidated financial statements.

Contractual Obligations and Commercial Commitments:

Information regarding our contractual obligations and commercial commitments at December 31, 2008 is summarized annually through 2013 and thereafter as follows:

(Millions of Dollars)	2009	2010	2011	2012	2013	Thereafter	Totals
Long-term debt maturities [a] [b]	$ 54.3	$ 4.3	$ 4.3	$ 267.3	$ 305.0	$3,207.8	$ 3,843.0
Estimated interest payments on existing debt [c]	222.7	219.2	218.9	210.1	194.4	2,114.8	3,180.1
Capital leases [d]	2.4	2.4	2.5	2.6	2.4	15.5	27.8
Operating leases [e]	24.6	18.9	7.1	6.1	5.9	23.9	86.5
Required funding of pension obligations [e] [f]	-	150.0	-	-	-	-	150.0
Required funding of other postretirement benefit obligations [e]	37.3	38.7	40.9	42.8	29.3	N/A	189.0
Estimated future annual regulated company costs [g]	791.6	723.9	779.7	715.0	523.6	2,855.2	6,389.0
Estimated future annual NU Enterprises costs [g]	40.3	41.9	42.9	38.8	44.7	-	208.6
Other purchase commitments [e] [h]	3,162.3	-	-	-	-	-	3,162.3
Totals [i] [j]	$4,335.5	$1,199.3	$1,096.3	$1,282.7	$1,105.3	$8,217.2	$17,236.3

(a) Included in our debt agreements are usual and customary positive, negative and financial covenants. Non-compliance with certain covenants, for example 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 maturities exclude $298.6 million of fees and interest due for spent nuclear fuel disposal costs, a positive $20.8 million of net changes in fair value and a negative $4.9 million of net unamortized premium and discount as of December 31, 2008.

(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 average of the 2008 floating-rate resets 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 $14.4 million as of December 31, 2008.

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

(f) The fair value of Pension Plan assets declined significantly during 2008. This decline resulted in a required contribution for the 2008 Pension Plan year. This contribution would be made just prior to the 2009 federal income tax return filing, which will likely be filed in the third quarter of 2010. We cannot determine at this time the amount of contributions that would be required for the 2009 Pension Plan year or future years.

(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. For further information on these estimated future annual costs, see Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the consolidated financial statements.

(h) Excludes FIN 48 unrecognized tax benefits of $156.3 million as of December 31, 2008, as we cannot make reasonable estimates of the periods or the potential amounts of cash settlement with the respective taxing authorities.

(i) 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 2009.

(j) Excludes other long-term liabilities, including a significant portion of the FIN 48 unrecognized tax benefits described above, environmental reserves ($26.8 million), various injuries and damages reserves ($35.4 million), employee medical insurance reserves ($6.6 million), long-term disability insurance reserves ($12 million) and the ARO liability reserves ($50.6 million) as we cannot make reasonable estimates of the periods.

RRB amounts are non-recourse to us, 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. For further information regarding our contractual obligations and commercial commitments, see the consolidated statements of capitalization and Note 2, "Short-Term Debt," Note 5A, "Employee Benefits - Pension Benefits and Postretirement Benefits Other Than Pensions," Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," Note 10, "Leases," and Note 11, "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, future financial performance or growth or 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 other 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 or inactions by local, state and federal regulatory bodies; changes in business and economic conditions, including their impact on interest rates, bad debt expense and demand for our products and services; changes in weather patterns; changes in laws, regulations or regulatory policy; changes in levels and timing of capital expenditures; disruptions in the capital markets or events that make our access to necessary capital more difficult or costly; 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	2008 over/(under) 2007		2007 over/(under) 2006	
	Amount	Percent	Amount	Percent
Operating Revenues	$(22)	- %	$(1,055)	(15)%
Operating Expenses:				
Fuel, purchased and net interchange power	(354)	(11)	(1,280)	(28)
Other operation	60	6	(160)	(14)
Maintenance	43	20	18	9
Depreciation	13	5	25	10
Amortization of regulatory assets, net	146	(a)	24	(a)
Amortization of rate reduction bonds	4	2	13	7
Taxes other than income taxes	15	6	1	1
Total operating expenses	(73)	(1)	(1,359)	(20)
Operating income	51	10	304	(a)
Interest expense, net	29	12	2	1
Other income, net	(11)	(18)	(3)	(4)
Income from continuing operations before income tax expense	11	3	299	(a)
Income tax expense/(benefit)	(4)	(3)	186	(a)
Preferred dividends of subsidiary	-	-	-	-
Income from continuing operations	15	6	113	85
Income/(loss) from discontinued operations	(1)	(100)	(337)	(100)
Net income/(loss)	$14	6%	$ (224)	(48)%

a) Percent greater than 100.

Net income was $14 million higher in 2008 as compared to 2007, primarily due to the growth in the company's transmission segment, partially offset by a $29.8 million after-tax charge associated with the settlement of litigation with Con Edison. Net income was $224 million lower in 2007 as compared to 2006 primarily due to the 2006 $314 million after-tax gain on the sale our competitive generation business.

Comparison of 2008 to 2007

Operating Revenues

	For the Twelve Months Ended December 31,		
(Millions of Dollars)	2008	2007	Variance
Electric distribution	$4,714	$4,927	$(213)
Gas distribution	577	514	63
Total distribution	5,291	5,441	(150)
Transmission	396	283	113
Regulated companies	5,687	5,724	(37)
Competitive businesses	113	98	15
Total	$5,800	$5,822	$ (22)

Operating revenues decreased $22 million in 2008 primarily due to lower revenues from the regulated companies ($37 million), partially offset by higher revenues from competitive businesses ($15 million). The lower regulated companies revenues were primarily due to the recovery of a lower level of CL&P distribution related expenses passed through to customers through regulatory tracking mechanisms. Competitive businesses revenues increased $15 million despite our continued exit from components of the competitive businesses due to higher Boulos revenues resulting from increased contractor billings ($10 million) and higher market prices for the remaining Select Energy wholesale contracts. Certain Select Energy contracts expired during 2008.

Revenues from the regulated companies decreased $37 million due to lower distribution segment revenues ($150 million), partially offset by higher transmission segment revenues ($113 million). Distribution segment revenues decreased $150 million primarily due to lower electric distribution revenues ($213 million), partially offset by higher gas distribution revenues ($63 million). Transmission segment revenues increased $113 million primarily due to a higher transmission investment base, the impact of the March 24, 2008 FERC ROE decision and higher operating expenses that are passed through to customers under FERC-approved transmission tariffs.

Electric distribution revenues decreased $213 million primarily due to the portion of revenues that does not impact earnings ($281 million) as a result of distribution revenue being included in regulatory tracking mechanisms and consolidation eliminations of transmission segment intracompany billings to the distribution segment, partially offset by the component of revenues that flows through to earnings ($68 million). The portion of the electric distribution segment revenues that flows through to earnings increased $68 million primarily due to increases in retail rates at each of the regulated companies ($89 million), partially offset by lower retail electric sales ($16 million). Retail electric sales decreased 3.5 percent in 2008 compared with 2007. Gas distribution revenues increased $63 million primarily due to increased recovery of higher gas costs, the rate increase effective July 1, 2007 and higher firm gas sales. Firm gas sales increased 2.1 percent in 2008 compared with 2007.

The $281 million electric distribution revenue decrease that does not impact earnings is due to the components of CL&P, PSNH and WMECO retail revenues that are included in regulatory commission approved tracking mechanisms that track the recovery of certain incurred costs ($179 million) and revenues that are eliminated in consolidation ($102 million). The distribution revenue tracking components decreased $179 million primarily due to revenues associated with the recovery of generation service and related congestion charges ($233 million) and CL&P delivery-related FMCC ($75 million) and lower PSNH SCRC ($55 million), partially offset by higher CL&P wholesale revenues primarily due to an increase in the market price of energy related to sales of IPP generation to ISO-NE ($59 million) and higher CL&P and PSNH retail transmission revenues ($82 million) mainly as a result of the higher 2008 rates and higher CL&P SBC revenue ($36 million). The tracking mechanisms allow for rates to be changed periodically with overcollections refunded to customers or undercollections recovered from customers in future periods.

Fuel, Purchased and Net Interchange Power

Fuel, purchased and net interchange power expenses decreased $354 million in 2008 due to lower costs at the regulated companies ($364 million), partially offset by higher competitive businesses expenses ($9 million). Fuel expense from the regulated companies decreased primarily at CL&P due to lower GSC supply costs, a decrease in deferred fuel costs and lower other purchased power costs. The decrease in GSC supply costs was primarily due to a reduction in load caused primarily by customer migration to third party suppliers and lower retail sales ($432 million), partially offset by higher Yankee Gas expenses ($41 million) primarily due to higher fuel prices in 2008 and higher PSNH fuel expense ($28 million) primarily due to higher forward energy market prices, partially offset by a decrease in payments to higher priced IPPs in 2008 as contracts expired. Competitive businesses' expenses increased due to higher Select Energy purchased power expenses related to the remaining wholesale contracts.

Other Operation
Other operation increased $60 million in 2008 primarily due to higher NU parent and other companies' expenses ($54 million), higher competitive businesses' expenses ($6 million) and higher regulated companies' distribution and transmission segment expenses ($1 million).

NU parent and other companies' expenses are higher by $54 million in 2008 primarily due to the $49.5 million payment to Con Edison resulting from the settlement of litigation. Competitive businesses' expenses are higher by $6 million primarily due to higher operating costs at the remaining services businesses.

Higher regulated companies' distribution and transmission segment expenses of $1 million are primarily due to higher transmission segment expenses ($8 million), expenses at Yankee Energy System, Inc. ($6 million) and higher electric distribution segment expenses ($4 million), partially offset by consolidation eliminations of transmission segment intracompany billings to the distribution segment, and further eliminations for NU consolidations and costs that are tracked and recovered through distribution tracking mechanisms ($18 million).

Maintenance
Maintenance expenses increased $43 million in 2008 primarily due to higher regulated companies' distribution expenses ($38 million) and higher transmission line expenses ($4 million). Distribution expenses are $38 million higher primarily due to higher PSNH generation expenses that are tracked and recovered through NHPUC approved tracking mechanisms ($15 million) mainly related to the Merrimack Station maintenance outages, higher tree trimming ($9 million), higher overhead line maintenance expenses ($5 million), substation equipment ($3 million) and line transformers ($2 million).

Depreciation
Depreciation increased $13 million in 2008 primarily due to higher regulated transmission and distribution plant balances resulting from completed construction programs put into service.

Amortization of Regulatory Assets, Net
Amortization of regulatory assets, net increased $146 million in 2008 for the distribution segment primarily due to higher amortization at CL&P ($144 million) resulting from a higher recovery of transition costs ($62 million), higher amortization of SBC ($50 million) and a credit in 2007 pertaining to the refund of the GSC overrecovery ($29 million).

Amortization of Rate Reduction Bonds
Amortization of RRBs increased $4 million in 2008. The higher portion of principal within the RRB payments results in a corresponding increase in the amortization of RRBs. This increase was partially offset by a decrease at PSNH resulting from the retirement of $50 million of RRBs in the first quarter of 2008.

Taxes Other than Income Taxes
Taxes other than income taxes increased $15 million in 2008 primarily due to higher Connecticut gross earnings tax ($16 million) mainly as a result of higher CL&P and Yankee Gas revenues that are subject to gross earnings tax and higher property taxes at CL&P and PSNH ($5 million) as a result of higher plant balances and higher local municipal tax rates, partially offset by lower payroll taxes charged to expense ($5 million).

Interest Expense, Net
Interest expense, net increased $29 million in 2008 primarily due to higher long-term debt interest ($31 million) resulting from the issuance of new long-term debt in 2007 and 2008 and higher other interest ($9 million) mostly related to short-term debt, partially offset by lower RRB interest resulting from lower principal balances outstanding ($11 million).

Other Income, Net
Other income, net decreased $11 million in 2008 primarily due to lower investment income ($16 million) primarily due to the absence of the higher NU investment income interest earned in 2007 on cash the parent received from the November 2006 sale of NU's competitive generation, higher investment losses ($14 million) primarily due to the supplemental benefit trust and lower equity in earnings of regional nuclear generating and transmission companies ($2 million), partially offset by higher AFUDC equity income ($12 million) and interest income related to the 2008 tax settlement ($10 million).

Income Tax Expense
Income tax expense decreased $4 million in 2008 primarily due to the Con Edison settlement ($20 million), temporary flow through plant differences ($6 million), partially offset by impacts associated with higher pre-tax earnings ($22 million).

Comparison of 2007 to 2006

Operating Revenues

	For the Twelve Months Ended December 31,		
(Millions of Dollars)	**2007**	**2006**	**Variance**
Electric distribution	$4,927	$5,332	$ (405)
Gas distribution	514	453	61
Total distribution	5,441	5,785	(344)
Transmission	283	200	83
Regulated companies	5,724	5,985	(261)
Competitive businesses	98	892	(794)
Total	$5,822	$6,877	$(1,055)

Net income is $224 million lower in 2007 due to the two significant gains in 2006 that 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 that are recovered under FERC-approved transmission tariffs.

Lower electric distribution revenues include the components of CL&P, PSNH and WMECO retail revenues that 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 that 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 $160 million in 2007 primarily due to lower NU Enterprises expenses ($115 million) and lower regulated companies distribution and transmission segment expenses ($49 million).

NU Enterprises' expenses decreased $115 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 that 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 ($21 million) and Summer Savings Rewards Program that was implemented in 2007 at CL&P as a result of a legislative act ($14 million).

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 RRBs increased $13 million in 2007. The higher portion of principal within the RRB payment results in a corresponding increase in the amortization of RRBs.

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 14, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements for a description and explanation of the discontinued operations.

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 the 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 internal controls over financial reporting were effective as of December 31, 2008.

February 27, 2009

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, 2008 and 2007, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company's internal control over financial reporting as of December 31, 2008, 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 4, the Company adopted Financial Accounting Standards Board Statement No. 157, Fair Value Measurements, as of January 1, 2008.

Deloitte & Touche LLP

Hartford, Connecticut
February 27, 2009

CONSOLIDATED BALANCE SHEETS

(Thousands of Dollars)	At December 31, 2008	2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 89,816	$ 15,104
Investments in securitizable assets (Note 1L)	-	308,182
Receivables, less provision for uncollectible accounts of $43,275 in 2008 and $25,529 in 2007	698,755	401,283
Unbilled revenues	218,440	101,860
Taxes receivable	-	13,850
Fuel, materials and supplies	300,049	210,850
Marketable securities - current	78,452	70,816
Derivative assets - current	31,373	105,517
Prepayments and other	88,679	58,794
	1,505,564	1,286,256
Property, Plant and Equipment:		
Electric utility	9,219,351	7,594,606
Gas utility	1,043,687	977,290
Other	290,156	310,535
	10,553,194	8,882,431
Less: Accumulated depreciation: $2,610,479 for electric and gas utility and $159,639 for other in 2008; $2,483,570 for electric and gas utility and $178,193 for other in 2007	2,770,118	2,661,763
	7,783,076	6,220,668
Construction work in progress	424,800	1,009,277
	8,207,876	7,229,945
Deferred Debits and Other Assets:		
Regulatory assets	3,502,606	2,057,083
Goodwill	287,591	287,591
Prepaid pension	-	202,512
Marketable securities - long-term	30,757	53,281
Derivative assets - long-term	241,814	298,001
Other	212,272	167,153
	4,275,040	3,065,621
Total Assets	$ 13,988,480	$ 11,581,822

(Thousands of Dollars)	At December 31, 2008	2007
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Notes payable to banks	$ 618,897	$ 79,000
Long-term debt - current portion	54,286	154,286
Accounts payable	678,614	598,546
Accrued taxes	12,527	-
Accrued interest	69,818	56,592
Derivative liabilities - current	100,919	71,601
Other	168,401	246,125
	1,703,462	1,206,150
Rate Reduction Bonds	686,511	917,436
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,223,461	1,067,490
Accumulated deferred investment tax credits	25,371	28,845
Deferred contractual obligations	193,016	222,908
Regulatory liabilities	592,540	851,780
Derivative liabilities - long-term	912,426	208,461
Accrued pension	740,930	-
Accrued postretirement benefits	240,371	181,507
Other	430,718	383,611
	4,358,833	2,944,602
Capitalization:		
Long-Term Debt	4,103,162	3,483,599
Preferred Stock of Subsidiary - Non-Redeemable	116,200	116,200
Common Shareholders' Equity:		
Common shares, $5 par value - authorized 225,000,000 shares; 176,212,275 shares issued and 155,834,361 shares outstanding in 2008 and 175,924,694 shares issued and 155,079,770 shares outstanding in 2007	881,061	879,623
Capital surplus, paid in	1,475,006	1,465,946
Deferred contribution plan - employee stock ownership plan	(15,481)	(26,352)
Retained earnings	1,078,594	946,792
Accumulated other comprehensive (loss)/income	(37,265)	9,359
Treasury stock, 19,708,136 shares in 2008 and 19,705,545 shares in 2007	(361,603)	(361,533)
Common Shareholders' Equity	3,020,312	2,913,835
Total Capitalization	7,239,674	6,513,634
Commitments and Contingencies (Note 7)		
Total Liabilities and Capitalization	$13,988,480	$11,581,822

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

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of Dollars, except share information)	For the Years Ended December 31, 2008	2007	2006
Operating Revenues	$ 5,800,095	$ 5,822,226	$ 6,877,687
Operating Expenses:			
Operation			
Fuel, purchased and net interchange power	2,996,180	3,350,673	4,630,798
Other	1,021,704	961,285	1,121,534
Maintenance	254,038	211,589	193,706
Depreciation	278,588	265,297	240,559
Amortization of regulatory assets, net	186,396	40,674	16,292
Amortization of rate reduction bonds	204,859	201,039	188,247
Taxes other than income taxes	267,565	252,188	250,580
Total operating expenses	5,209,330	5,282,745	6,641,716
Operating Income	590,765	539,481	235,971
Interest Expense:			
Interest on long-term debt	193,883	162,841	141,579
Interest on rate reduction bonds	50,231	61,580	74,242
Other interest	25,031	15,824	22,375
Interest expense, net	269,145	240,245	238,196
Other Income, Net	50,428	61,639	64,394
Income from Continuing Operations Before Income Tax Expense/(Benefit)	372,048	360,875	62,169
Income Tax Expense/(Benefit)	105,661	109,420	(76,326)
Income from Continuing Operations Before Preferred Dividends of Subsidiary	266,387	251,455	138,495
Preferred Dividends of Subsidiary	5,559	5,559	5,559
Income from Continuing Operations	260,828	245,896	132,936
Discontinued Operations (Note 14):			
Income from Discontinued Operations	-	435	31,321
Gains from Sale/Disposition of Discontinued Operations	-	2,054	504,314
Income Tax Expense	-	1,902	197,993
Income from Discontinued Operations	-	587	337,642
Net Income	$ 260,828	$ 246,483	$ 470,578
Basic Earnings Per Common Share:			
Income from Continuing Operations	$ 1.68	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	2.20
Basic Earnings Per Common Share	$ 1.68	$ 1.59	$ 3.06
Fully Diluted Earnings Per Common Share:			
Income from Continuing Operations	$ 1.67	$ 1.59	$ 0.86
Income from Discontinued Operations	-	-	2.19
Fully Diluted Earnings Per Common Share	$ 1.67	$ 1.59	$ 3.05
Basic Common Shares Outstanding (weighted average)	155,531,846	154,759,727	153,767,527
Fully Diluted Common Shares Outstanding (weighted average)	155,999,240	155,304,361	154,146,669

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Years Ended December 31,		
(Thousands of Dollars)	2008	2007	2006
Net Income	$ 260,828	$ 246,483	$ 470,578
Other comprehensive (loss)/income, net of tax:			
Qualified cash flow hedging instruments	(6,909)	(3,591)	(12,340)
Changes in unrealized gains on securities	(1,669)	(101)	718
Change in funded status of pension, SERP and other post retirement plans	(38,046)	8,553	-
Minimum SERP liability	-	-	379
Other comprehensive (loss)/income, net of tax	(46,624)	4,861	(11,243)
Comprehensive Income	$ 214,204	$ 251,344	$ 459,335

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

CONSOLIDATED STATEMENTS OF COMMON 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 Income/(Loss)	Treasury Stock	Total
Balance as of January 1, 2006	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
Net income for 2008					260,828			260,828
Dividends on common shares - $0.825 per share					(129,026)			(129,026)
Issuance of common shares, $5 par value	287,581	1,438	4,086					5,524
Allocation of benefits - ESOP	469,601		865	10,871				11,736
Change in restricted shares, net	(2,591)		2,436				(70)	2,366
Tax deduction for stock options exercised and Employee Stock Purchase Plan disqualifying dispositions			1,622					1,622
Capital stock expenses, net			51					51
Other comprehensive loss						(46,624)		(46,624)
Balance as of December 31, 2008	155,834,361	$ 881,061	$ 1,475,006	$(15,481)	$ 1,078,594	$(37,265)	$(361,603)	$ 3,020,312

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Dollars)	For the Years Ended December 31, 2008	2007	2006
Operating Activities:			
Net income	$ 260,828	$ 246,483	$ 470,578
Adjustments to reconcile to net cash flows provided by operating activities:			
Pre-tax gains from sale/disposition of discontinued operations	-	(2,054)	(504,314)
Bad debt expense	28,573	29,140	29,366
Depreciation	278,588	265,297	243,822
Deferred income taxes	86,810	6,933	(204,212)
Amortization of investment tax credits	(3,474)	(3,583)	(3,673)
Pension and PBOP expense and contributions, net of capitalized portion	(3,839)	10,865	38,994
Stock-based compensation expense	13,518	13,855	14,718
Allowance for equity funds used during construction	(29,028)	(17,417)	(13,573)
Impairment of marketable securities	17,399	2,539	-
(Deferral)/amortization of recoverable energy costs	(10,590)	11,715	15,609
Amortization of rate reduction bonds	204,859	201,039	188,247
Amortization of regulatory assets, net	186,396	40,674	16,292
Regulatory (refunds and underrecoveries)/overrecoveries	(174,662)	37,010	(96,560)
Derivative assets and liabilities	(37,052)	(43,808)	(90,867)
Deferred contractual obligations	(32,326)	(41,950)	(90,671)
(Increase)/decrease in other deferred debits	(16,873)	(5,026)	2,837
Increase/(decrease) in other deferred credits	4,735	(8,784)	(10,451)
Other adjustments	(5,738)	(4,464)	22,921
Changes in current assets and liabilities:			
Receivables and unbilled revenues, net	(141,879)	(65,381)	605,366
Fuel, materials and supplies	(74,531)	(33,727)	16,718
Investments in securitizable assets	(25,787)	33,531	(158,651)
Other current assets	(4,677)	3,878	58,350
Accounts payable	72,791	(49,554)	(399,386)
Counterparty deposits and margin special deposits	(7,474)	29,505	26,469
Taxes receivable/accrued	63,251	(392,611)	271,477
Other current liabilities	(400)	(15,670)	(42,332)
Net cash flows provided by operating activities	649,418	248,435	407,074
Investing Activities:			
Investments in property and plant	(1,255,407)	(1,114,824)	(872,181)
Net proceeds from sales of competitive businesses	-	-	1,053,099
Cash payments related to the sale of competitive businesses	-	(16,648)	(32,359)
Proceeds from sales of marketable securities	259,361	254,832	193,459
Purchases of marketable securities	(262,357)	(261,777)	(193,917)
Rate reduction bond escrow and other deposits	1,686	63,722	(50,686)
Other investing activities	3,360	7,229	19,649
Net cash flows (used in)/provided by investing activities	(1,253,357)	(1,067,466)	117,064
Financing Activities:			
Issuance of common shares related to share-based compensation	5,524	9,056	9,494
Cash dividends on common shares	(129,077)	(120,988)	(112,745)
Increase/(decrease) in short-term debt	539,897	79,000	(32,000)
Issuance of long-term debt	760,000	655,000	250,000
Reacquisition and retirements of long-term debt	(261,286)	(4,877)	(28,843)
Retirements of rate reduction bonds	(230,925)	(259,722)	(173,344)
Other financing activities	(5,482)	(5,245)	(571)
Net cash flows provided by/(used in) financing activities	678,651	352,224	(88,009)
Net increase/(decrease) in cash and cash equivalents	74,712	(466,807)	436,129
Cash and cash equivalents - beginning of year	15,104	481,911	45,782
Cash and cash equivalents - end of year	$ 89,816	$ 15,104	$ 481,911

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands of Dollars)		At December 31, 2008	2007
Common Shareholders' Equity		$ 3,020,312	$ 2,913,835
Preferred Stock:			
CL&P Preferred Stock Not Subject to Mandatory Redemption - $50 par value - authorized 9,000,000 shares in 2008 and 2007; 2,324,000 shares outstanding in 2008 and 2007; 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%	67,143	71,429
2014-2018	4.80% to 6.90%	1,205,000	695,000
2019-2024	5.26% to 8.48%	209,845	209,845
2026-2037	5.35% to 6.375%	830,000	830,000
Total First Mortgage Bonds		2,311,988	1,806,274
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% and Variable Rate in 2008; 3.35% in 2007	62,000	62,000
Other:			
2008-2009	Variable Rate and 3.30%	-	195,000
2012-2015	5.00% to 7.25%	618,000	368,000
2034-2037	5.90% to 6.70%	90,000	90,000
Total Pollution Control Notes and Other		1,592,985	1,537,985
Total First Mortgage Bonds, Pollution Control Notes and Other		3,904,973	3,344,259
Fees and interest due for spent nuclear fuel disposal costs		298,555	294,305
Change in fair value resulting from interest rate hedge instrument		20,828	4,172
Unamortized premium and discount, net		(4,908)	(4,851)
Reacquisition of Pollution Control Notes		(62,000)	-
Total Long-Term Debt		4,157,448	3,637,885
Less: Amounts due within one year		54,286	154,286
Long-Term Debt		4,103,162	3,483,599
Total Capitalization		$7,239,674	$6,513,634

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, Inc. (NU Enterprises), as described below. NU was formed on July 1, 1966 when The Connecticut Light and Power Company (CL&P), Western Massachusetts Electric Company (WMECO) and The Hartford Electric Light Company affiliated under the common ownership of the NU system. In 1967, Holyoke Water Power Company (HWP) joined the affiliation. In 1992, Public Service Company of New Hampshire (PSNH) became a subsidiary of NU parent. On March 1, 2000, gas became an integral part of NU's Connecticut operations when NU's merger with Yankee Energy System, Inc. (Yankee) and its principal subsidiary, Yankee Gas Services Company (Yankee Gas), was completed. 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 electric 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: CL&P, PSNH and WMECO furnish franchised retail electric service in Connecticut, New Hampshire and Massachusetts, respectively. Yankee Gas owns and operates Connecticut's largest natural gas distribution system. CL&P, PSNH and WMECO's results include the operations of its distribution and transmission segments. PSNH's distribution results include the operations of its generation business. Yankee Gas' results include the operations of its gas distribution segment.

NU Enterprises: NU Enterprises is the parent company of Select Energy, Inc. (Select Energy), E. S. Boulos Company (Boulos), Northeast Generation Services Company (NGS), NGS Mechanical, Inc. and Select Energy Contracting, Inc. (SECI), which are collectively referred to as NU Enterprises. For information regarding NU's exit from certain of these businesses, see Note 14, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

B. Presentation

The consolidated financial statements of NU include the accounts of all its 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 for the years ended December 31, 2007 and 2006 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 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), and
- SECI (including Reeds Ferry Supply Co., Inc.).

For further information regarding discontinued operations, see Note 14, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

C. Accounting Standards Issued But Not Yet Adopted

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is effective January 1, 2009. SFAS No. 160 requires ownership interests in subsidiaries held by third parties (noncontrolling interests) to be presented within equity and clearly identified and labeled. It sets forth requirements for income statement presentation related to the activities of noncontrolling interests and for accounting for changes in ownership interests and provides guidance for deconsolidation. Implementation of SFAS No. 160 is not expected to have a material impact on the company's consolidated financial statements.

In June 2008, the FASB issued FASB Staff Position (FSP) EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities," which is effective January 1, 2009 and is required to be applied retrospectively. As a result of this FSP, NU's restricted stock awards that were not vested in 2007 and the first quarter of 2008 are considered participating securities in calculating earnings per share (EPS) for these periods using the two-class method. NU's restricted stock awards were completely vested during the first quarter of 2008 and are no longer awarded. FSP EITF 03-6-1 is not expected to impact NU's EPS for any period.

SFAS No. 157, "Fair Value Measurements," which establishes a framework for identifying and measuring fair value, was issued in 2006 and applied in 2008 to the fair value measurements of financial assets and liabilities of NU and its subsidiaries. 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 is required to be applied to nonrecurring fair value measurements of non-financial assets and liabilities beginning in 2009, including asset retirement obligations (ARO) and goodwill and other impairment analyses. Implementation of SFAS No. 157 to non-financial assets and liabilities is not expected to have a material impact on the company's 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. The 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.

The regulated companies record monthly, day ahead and real time energy purchases and sales, net in accordance with 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." Revenues associated with derivative instruments to purchase and sell in the day ahead and real time markets are recorded net in revenues and fuel, purchased and net interchange power.

Regulated Companies' Unbilled Revenues: Unbilled revenues represent an estimate of electricity or gas delivered to customers for which the customers have not yet been billed. Unbilled revenues are included in revenue on the statement of income 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.

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 Schedule 21 - NU rate schedules to recover fees for 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 Schedule 21 - NU 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 100 percent of the construction work in progress (CWIP) that is included in rate base on the New England East-West Solutions (NEEWS) projects. The Schedule 21 - NU 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 Schedule 21 - NU 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 customers. At December 31, 2008, the Schedule 21 - NU rates were in a total underrecovery position of $4.6 million that will be collected from customers in mid-2009.

Regulated Companies' Transmission Revenues - Retail Rates: A significant portion of the NU consolidated transmission segment revenue comes from ISO-NE charges to the distribution segments of CL&P, PSNH and WMECO, each of which recovers these costs through rates charged to their retail customers. CL&P, PSNH and WMECO each have a retail transmission cost tracking mechanism as part of their rates, which allows the companies to charge their retail customers for transmission costs 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. Wholesale marketing revenues are recognized through mark-to-market accounting on underlying derivative contracts and recorded in fuel, purchased and net interchange power. This net presentation of the mark-to-market and settlement amounts is required because NU Enterprises cannot assert that physical delivery of contract quantities is deemed 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 is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of the normal purchases and sales exception, identifying, electing and designating 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 the consolidated financial statements.

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 fair value of derivative assets and liabilities with the same counterparty are offset as permitted under FASB Interpretation No. (FIN) 39, "Offsetting of Amounts Related to Certain Contracts - an Interpretation of APB Opinion No. 10 and FASB Statement No. 105."

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. CL&P and WMECO have elected normal on many derivative contracts. 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 prospectively.

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.

All but one of Select Energy's remaining wholesale marketing contracts are derivatives, and many of NU's regulated company contracts for the purchase or sale of energy or energy-related products are derivatives.

EITF 03-11 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," prohibited 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) were not recorded on the balance sheet as of December 31, 2007. These initial losses were recorded upon adoption of SFAS No. 157 on January 1, 2008. For further information, see Note 1F, "Fair Value Measurements," to the consolidated financial statements.

For further information regarding derivative contracts and their accounting, see Note 3, "Derivative Instruments," to the consolidated financial statements.

F. Fair Value Measurements

On January 1, 2008, NU and its subsidiaries adopted SFAS No. 157, "Fair Value Measurements," which establishes a framework for defining and measuring fair value and requires expanded disclosures about fair value measurements. SFAS No. 157:

- Defines fair value as the price that would be received for the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price).
- Establishes a three-level fair value hierarchy based upon the observability of inputs to the valuations of assets and liabilities.
- Requires consideration of the company's own creditworthiness and risk of nonperformance when valuing its liabilities.
- Required prospective implementation with adjustments to fair value reflected in earnings, similar to a change in estimate, with exceptions including recognition of previously deferred initial gains or losses described below.
- Required recognition in retained earnings of previously deferred initial gains or losses on derivative contracts whose estimated fair values are based on significant unobservable inputs. Recognition of the initial gains or losses was previously prohibited under EITF 02-3. CL&P's initial gains and losses on its CfDs that would have been recorded in retained earnings upon adoption were recorded as regulatory assets and liabilities because their costs or benefits are expected to be fully recovered from or refunded to customers.

Upon adoption, the company applied SFAS No. 157 to the regulated and unregulated companies' derivative contracts that are recorded at fair value and to the marketable securities held in the Trust Under Supplemental Executive Retirement Plan (SERP) ("supplemental benefit trust"), established for non-pension retirement benefits, and WMECO's spent nuclear fuel trust. The company also applied SFAS No. 157 to investment valuations used to calculate the funded status of NU's pension and postretirement benefit plans as of December 31, 2008. In 2009, the company will be required to apply SFAS No. 157 to nonrecurring fair value measurements of non-financial assets and liabilities, such as goodwill and AROs.

As a result of adopting SFAS No. 157, the company recorded a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to derivative liabilities for its remaining unregulated wholesale marketing contracts. In 2008, the company recorded a $0.8 million pre-tax benefit to partially reverse the exit price impact recorded under SFAS No. 157 as the company served out rather than exited the contracts.

The company also recorded changes in fair value of certain derivative contracts of CL&P. Because CL&P is a cost-of-service, rate regulated entity, the cost or benefit of the contracts is expected to be fully recovered from or refunded to CL&P's customers, and an offsetting regulatory asset or liability was recorded to reflect these changes. As of January 1, 2008, implementing SFAS No. 157 resulted in a total increase to CL&P's derivative liabilities, with an offset to regulatory assets, of approximately $590 million, and a total decrease to derivative assets, with an offset to regulatory liabilities, of approximately $30 million.

Fair Value Hierarchy: As required by SFAS No. 157, in measuring fair value the company uses observable market data when available and minimizes the use of unobservable inputs. Unobservable inputs are needed to value certain derivative contracts due to complexities in contractual terms and the long duration of contracts. SFAS No. 157 requires inputs used in fair value measurements to be categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement.

The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products. Significant unobservable inputs are used in the valuations, including items such as energy and energy-related product prices in future years for which observable prices are not yet available, future contract quantities under full-requirements or supplemental sales contracts, and market volatilities. Items valued using these valuation techniques are classified according to the lowest level for which there is at least one input that is significant to the valuation. Therefore, an item may be classified in Level 3 even though there may be some significant inputs that are readily observable.

Determination of Fair Value: The following is a description of the valuation techniques utilized in NU's fair value measurements:

Derivative contracts: Many of the company's derivative positions that are recorded at fair value are classified as Level 3 within the fair value hierarchy and are valued using models that incorporate both observable and unobservable inputs. Fair value is modeled using techniques such as discounted cash flow approaches adjusted for assumptions relating to exit price and the Black-Scholes option pricing model, incorporating the terms of the contracts. Significant unobservable inputs utilized in the valuations include energy and energy-related product prices for future years for long-dated derivative contracts, future contract quantities under full requirements and supplemental sales contracts, and market volatilities. Discounted cash flow valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using available historical market transaction information. Valuations of derivative contracts also reflect nonperformance risk, including credit. The derivative contracts classified as Level 3 include NU Enterprises' remaining wholesale marketing contract and its related supply contracts, CL&P's CfDs, CL&P's contracts with certain independent power producers (IPPs), PSNH and Yankee Gas options and CL&P and PSNH financial transmission rights (FTRs).

Other derivative contracts recorded at fair value are classified as Level 2 within the fair value hierarchy. An active market for the same or similar contracts exists for these contracts, which include PSNH forward contracts to purchase energy and interest rate swap agreements for the regulated companies and NU parent. For these contracts, valuations are based on quoted prices in the market and include some modeling using market-based assumptions.

For further information on derivative contracts, see Note 3, "Derivative Instruments," to the consolidated financial statements.

Marketable securities: NU and WMECO hold in trust marketable securities, which include equity securities, mutual funds and cash equivalents, and fixed maturity securities.

Equity securities, mutual funds and cash equivalents are classified as Level 1 in the fair value hierarchy. These investments are traded in active markets and quoted prices are available for identical investments.

Fixed maturity securities classified as Level 2 within the fair value hierarchy include U.S. Treasury securities, corporate bonds, collateralized mortgage obligations, U.S. pass-through bonds, asset-backed securities, commercial mortgage-backed securities, and commercial paper. The fair value of these instruments is estimated using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures.

For further information see Note 4, "Fair Value Measurements," and Note 9,"Marketable Securities," to the consolidated financial statements.

G. 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 Yankee Gas' 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, the majority of deferred benefit costs and regulatory assets offsetting regulated company derivative liabilities, 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.

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

	At December 31,	
(Millions of Dollars)	**2008**	**2007**
Securitized assets	$ 677.4	$ 907.0
Income taxes, net	355.4	335.5
Deferred benefit costs	1,140.9	201.4
Unrecovered contractual obligations	169.1	189.9
Regulatory assets offsetting regulated company derivative liabilities	844.2	122.3
CL&P undercollections	75.2	90.6
Other regulatory assets	240.4	210.4
Totals	$ 3,502.6	$ 2,057.1

Additionally, the regulated companies had $68.3 million and $11.9 million of regulatory costs at December 31, 2008 and 2007, respectively, which were included in deferred debits and other assets - other on the accompanying consolidated balance sheets. These amounts represent incurred costs that have not yet been approved for recovery by the applicable regulatory agency. Of the $68.3 million, $62.7 million relates to costs incurred at PSNH relating to December 2008 storm restorations that met the New Hampshire Public Utilities Commission (NHPUC) specified criteria for deferral to a major storm cost reserve. Management believes these costs are recoverable in future cost-of-service regulated rates.

Securitized Assets: In March 2001, CL&P issued $1.4 billion in rate reduction bonds (RRBs). CL&P used $1.1 billion of the proceeds from that issuance to buyout or buydown certain contracts with IPPs. The unamortized CL&P securitized asset balance was $322.9 million and $468.6 million at December 31, 2008 and 2007, respectively, which includes $44.9 million and $65.1 million, respectively, related to unrecovered contractual obligations. CL&P also used the proceeds from the issuance of the RRBs 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 $54.9 million and $79.6 million at December 31, 2008 and 2007, respectively.

In April 2001, PSNH issued RRBs 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 $227.6 million and $272.4 million at December 31, 2008 and 2007, respectively. In January 2002, PSNH issued an additional $50 million in RRBs and used the proceeds from that issuance to repay short-term debt that was incurred to buyout a purchased-power contract in December 2001. The unamortized PSNH securitized asset balance for the January 2002 issuance was $0.8 million at December 31, 2007. The January 2002 RRBs were paid in full in the first quarter of 2008.

In May 2001, WMECO issued $155 million in RRBs and used the majority of the proceeds from that issuance to buyout an IPP contract. The unamortized WMECO securitized asset balance was $72 million and $85.6 million at December 31, 2008 and 2007, respectively.

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

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 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. For further information regarding income taxes, see Note 1H, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial statements.

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 at December 31, 2008 and 2007 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 Northeast Utilities Service Company (NUSCO) costs that support the regulated companies, as these amounts are also recoverable. The deferred benefit costs of CL&P and PSNH are not in rate base and are being recovered over a period of up to 12 years. WMECO's deferred benefit costs are in rate base.

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 was recorded as unrecovered contractual obligations regulatory assets at December 31, 2008 and 2007. A portion of these obligations for CL&P was securitized in 2001 and was included in securitized regulatory assets. Amounts for CL&P are being recovered through the Competitive Transition Assessment (CTA). 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. Included in these amounts are $677.8 million and $86.7 million at December 31, 2008 and 2007, respectively, of derivative liabilities relating to CL&P's capacity contracts, referred to as CfDs. See Note 3, "Derivative Instruments," to the consolidated financial statements for further information. This asset is excluded from rate base.

CL&P Undercollections: 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, 2008 and 2007, SBC undercollections totaled $43.3 million and $36.6 million, respectively.

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, 2008, CL&P's GSC and FMCC was recorded as a $31.9 million regulatory asset as GSC and FMCC unrecovered costs were in excess of GSC and FMCC collections. At December 31, 2007, GSC and FMCC collections were in excess of GSC and FMCC costs, and a $119.2 million regulatory liability was recorded.

The CTA allows CL&P to recover stranded costs, such as securitization costs associated with the RRBs, amortization of regulatory assets, and IPP over market costs. At December 31, 2007, CL&P's CTA was recorded as a $54 million regulatory asset as CTA unrecovered costs were in excess of CTA collections. At December 31, 2008, CTA collections were in excess of CTA costs, and a $69.5 million regulatory liability was recorded.

Other Regulatory Assets: Other regulatory assets at December 31, 2008 and 2007 consisted of the following:

	At December 31,	
(Millions of Dollars)	**2008**	**2007**
Asset retirement obligations	$ 42.3	$ 40.6
Losses on reacquired debt	26.4	28.8
Environmental costs	27.2	29.3
Storm reserves	19.3	6.8
Buyout/buydown of other IPP contracts	14.2	16.1
Write-off of uncollectible hardship receivables	16.0	26.8
Conservation & load management deferral	19.1	13.3
Recoverable nuclear costs	5.0	9.3
Recoverable energy costs	0.7	1.3
Other	70.2	38.1
Total other regulatory assets	$240.4	$210.4

The regulatory assets above associated with the implementation of FIN 47, "Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143," included $12 million and $11.6 million at December 31, 2008 and 2007, respectively, related to PSNH that have been approved for future recovery. As part of WMECO's rate case settlement, the Massachusetts Department of Public Utilities (DPU) approved accounting requirements setting forth the recognition of its AROs and a corresponding regulatory asset. Management believes that recovery of the remaining FIN 47 regulatory assets is probable.

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

	At December 31,	
(Millions of Dollars)	**2008**	**2007**
Cost of removal	$226.0	$262.6
Regulatory liabilities offsetting regulated company derivative assets	137.8	330.4
CL&P overcollections	69.5	119.2
CL&P AFUDC transmission incentive (Note 1K)	47.6	21.4
PSNH deferred ES revenue, net	33.0	17.6
Pension and PBOP liabilities - Yankee Gas acquisition	17.6	20.7
Overrecovered gas costs	16.9	10.4
Other regulatory liabilities	44.1	69.5
Totals	$592.5	$851.8

Cost of Removal: NU's regulated companies currently recover amounts in rates for future costs of removal of plant assets. These amounts 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. See Note 3, "Derivative Instruments," to the consolidated financial statements for further information. This liability is excluded from rate base.

CL&P Overcollections: As noted previously, the CTA allows CL&P to recover stranded costs, the GSC allows CL&P to recover the costs of the procurement of energy for standard service and the FMCC allows CL&P to recover the costs of power market rules by the FERC. At December 31, 2008, CTA overcollections totaled $69.5 million and were recorded as a regulatory liability while GSC and FMCC undercollections totaled $31.9 million and was recorded as a regulatory asset. At December 31, 2007, GSC and FMCC overcollections totaled $119.2 million and was recorded as a regulatory liability while CTA undercollections totaled $54 million and was recorded as a regulatory asset.

PSNH Deferred ES Revenue, Net: PSNH default energy service (ES) revenues and costs are fully tracked, and the difference between ES revenues and costs are deferred. ES deferrals are being collected from/refunded to customers through a charge/(credit) in the subsequent ES rate period.

Pension and PBOP Liabilities - Yankee Gas Acquisition: When Yankee Gas was acquired by NU, the Pension and PBOP liabilities were adjusted to fair value with offsets to these adjustments recorded as regulatory liabilities, as approved by the Connecticut Department of Public Utility Control (DPUC).

Overrecovered Gas Costs: The Yankee Gas regulated rates include a Purchased Gas Adjustment (PGA) clause under which gas costs below base rate levels calculated annually on August 31st are returned to customers. Differences between the actual gas costs and the current base rate recovery amounts are deferred and returned in future periods.

H. 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:

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
The components of the federal and state income tax provisions are:			
Current income taxes:			
Federal	$ 6.0	$ 89.3	$ 59.7
State	16.3	18.9	(19.1)
Total current	22.3	108.2	40.6
Deferred income taxes, net:			
Federal	100.2	26.2	(49.7)
State	(13.4)	(21.4)	(4.2)
Total deferred	86.8	4.8	(53.9)
Investment tax credits, net	(3.4)	(3.6)	(63.0)
Income tax expense/(benefit)	$ 105.7	$ 109.4	$ (76.3)

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

	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	**2008**	**2007**	**2006**
Income from continuing operations before income tax expense/(benefit)	$372.0	$ 360.9	$ 62.2
Expected federal income tax expense/(benefit)	130.2	126.3	21.7
Tax effect of differences:			
Depreciation	(12.9)	(6.6)	(4.0)
Amortization of regulatory assets	0.2	0.2	13.3
Investment tax credit amortization (including $59.3 million in 2006 related to the CL&P PLR)	(3.4)	(3.6)	(63.0)
Other federal tax credits	(4.6)	(4.2)	(0.3)
State income taxes, net of federal impact	(9.5)	(9.6)	(16.8)
Excess deferred income taxes - CL&P PLR	-	-	(14.7)
Deferred tax adjustment - sale to affiliate	-	-	(6.0)
Medicare subsidy	(4.2)	(4.4)	(5.5)
Tax asset valuation allowance/reserve adjustments	12.5	10.5	1.4
Other, net	(2.6)	0.8	(2.4)
Income tax expense/(benefit)	$105.7	$ 109.4	$ (76.3)
Effective tax rate	28.4%	30.3%	* %

*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 had been sold totaled $59 million and $15 million, respectively, and $74 million combined. Later in 2006, the 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 was $38 million in 2006.

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

	At December 31,	
(Millions of Dollars)	**2008**	**2007**
Deferred tax liabilities - current:		
Derivative asset and change in fair value of energy contracts	$ 12.5	$ 21.9
Property tax accruals and other	47.5	52.2
Total deferred tax liabilities - current	60.0	74.1
Deferred tax assets - current:		
Derivative liability and change in fair value of energy contracts	42.4	11.0
Allowance for uncollectible accounts and other	35.3	22.7
Total deferred tax assets - current	77.7	33.7
Net deferred tax (assets)/liabilities - current	(17.7)	40.4
Deferred tax liabilities - long-term:		
Accelerated depreciation and other plant-related differences	1,155.4	967.5
Employee benefits	3.8	167.8
Regulatory amounts:		
Securitized contract termination costs	135.3	167.0
Other regulatory deferrals	875.8	93.9
Income tax gross-up	192.6	194.7
Derivative assets	88.1	111.1
Other	10.7	66.5
Total deferred tax liabilities - long-term	2,461.7	1,768.5
Deferred tax assets - long-term:		
Regulatory deferrals	168.2	192.2
Employee benefits	481.3	280.3
Income tax gross-up	29.0	34.0
Derivative liability	364.8	54.2
Other	211.3	164.6
Total deferred tax assets - long-term	1,254.6	725.3
Less: valuation allowance	16.4	24.3
Net deferred tax assets - long-term	1,238.2	701.0
Net deferred tax liabilities - long-term	1,223.5	1,067.5
Net deferred tax liabilities	$ 1,205.8	$ 1,107.9

Net deferred tax (assets)/liabilities - current are recorded as current assets or liabilities and are included in prepayments and other or current liabilities - other, respectively, on the accompanying consolidated balance sheets.

At December 31, 2008, NU had state net operating loss (NOL) carryforwards of $269.1 million that expire between December 31, 2010 and December 31, 2028 and state credit carryforwards of $90.8 million that expire by December 31, 2013. At December 31, 2007, NU had state 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.

On July 3, 2008, Massachusetts amended its corporate excise tax provisions, which are effective for tax years beginning on or after January 1, 2009. Companies, including WMECO, must account for the impact of income tax law changes in the period that includes the enactment date of the law change. As a result, NU recorded an estimate of the impact of the new legislation as a $11.9 million decrease to deferred tax liabilities and a decrease to regulatory assets on its consolidated balance sheet as of December 31, 2008.

Effective on January 1, 2007, NU and its subsidiaries 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.

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

Interest on uncertain tax positions is recorded and generally classified as a component of other interest expense. However, when resolution of uncertainties results in the company receiving interest income, any related interest benefit is recorded in other income, net on the accompanying consolidated statements of income. 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, net on the accompanying consolidated statements of income. As of December 31, 2008 and 2007, NU recognized accrued interest expense of $38.7 million and $21.8 million, respectively, on the accompanying consolidated balance sheets. For the years ended December 31, 2008 and 2007, NU recognized other interest expense of $8.2 million and $2.4 million, respectively, on the accompanying consolidated statements of income.

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, 2008 and 2007, the portion of unrecognized tax benefits that would impact the effective tax rate, if recognized, was $120 million and $93 million, respectively.

A reconciliation of the activity in unrecognized tax benefits from January 1, 2007 to December 31, 2008 is as follows:

(Millions of Dollars)	
Balance at January 1, 2007	$ 86.1
Gross increases - current year	25.0
Gross increases - prior year	10.6
Lapse of statute of limitations	(0.6)
Balance at December 31, 2007	121.1
Gross increases - current year	28.6
Gross increases - prior year	7.4
Lapse of statute of limitations	(0.8)
Balance at December 31, 2008	$156.3

Tax Positions: In September 2008, NU and the IRS reached a settlement agreement related to the timing for deducting certain costs. This agreement closed the federal tax years 2002 through 2004 and resulted in a refund of $123 million less a $35 million payment for 2005. The issues regarding the timing for deducting these costs are also subject to review during the 2005 through 2007 IRS federal audit cycle and therefore are not considered effectively settled for years after 2004. While this settlement resulted in $10.1 million of pre-tax interest income, it did not have a significant impact on income tax expense. NU is currently working to resolve certain tax matters regarding the timing for certain deductions in the open federal tax years. While discussions are currently ongoing with federal and state taxing authorities, 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, which are primarily related to timing differences, could result in a $2 million to $42 million decrease in unrecognized tax benefits. These estimated changes are related to timing, as well as state tax impacts, which could have an impact on earnings of $1 million to $4 million in 2009.

Tax Years: The following table summarizes NU's tax years that remain subject to examination by major tax jurisdictions at December 31, 2008:

Description	Tax Years
Federal	2005 - 2008
Connecticut	1997 - 2008
New Hampshire	2005 - 2008
Massachusetts	2005 - 2008

I. Property, Plant and Equipment and Accumulated Depreciation

The following table summarizes NU's investments in utility plant at December 31, 2008 and 2007 and the average depreciable life at December 31, 2008:

	Average Depreciable Life	At December 31, 2008	2007
	(Years)	(Millions of Dollars)	
Distribution	33.7	$6,644.4	$6,230.3
Transmission	59.6	2,981.2	1,751.1
Generation	31.6	637.5	590.5
Competitive energy	5.6	12.8	18.7
Other	18.0	277.3	291.8
Total property, plant and equipment		10,553.2	8,882.4
Less: Accumulated depreciation		2,770.1	2,661.8
Net property, plant and equipment		7,783.1	6,220.6
Construction work in progress		424.8	1,009.3
Total property, plant and equipment, net		$8,207.9	$7,229.9

NU uses the direct expense method to account for planned major maintenance expenses primarily related to generation at PSNH. NU charges planned major maintenance activities to operating expense unless the cost represents the acquisition of additional components. NU capitalizes the cost of plant additions.

In 2008, NU entered into certain equipment purchase contracts that required the company to make advance payments during the design, manufacturing, shipment and installation of equipment. As of December 31, 2008, these advance payments totaled $13.8 million and are included in construction work in progress on the accompanying consolidated balance sheets.

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 composite rates of 3 percent in 2008 and 3.2 percent in 2007 and 2006.

J. Equity Method Investments

Regional Nuclear Companies: At December 31, 2008, 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 that has been decommissioned. NU's ownership interests in the Yankee Companies at December 31, 2008, which are accounted for on the equity method, are 49 percent of CYAPC, 38.5 percent of YAEC and 20 percent of MYAPC.

The total carrying value of NU's ownership interests in CYAPC, YAEC and MYAPC, 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 $7.2 million and $6.6 million at December 31, 2008 and 2007, respectively.

Net earnings related to these equity investments are included in other income, net on the accompanying consolidated statements of income. For further information, see Note 1R, "Summary of Significant Accounting Policies - Other Income, Net," to the consolidated financial statements.

For further information, see Note 7E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements.

Hydro-Québec: NU parent has a 22.7 percent equity ownership interest in two companies that transmit electricity imported from the Hydro-Québec system in Canada. NU parent's investment, which is included in deferred debits and other assets - other on the accompanying consolidated balance sheets, totaled $7.2 million and $7.6 million at December 31, 2008 and 2007, respectively.

The application of the equity method is considered the appropriate method to account for the Yankee Companies and the Hydro-Québec investments because NU has the ability to exercise significant influence over the investees' operating and financial policies.

K. Allowance for Funds Used During Construction

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, net on the accompanying consolidated statements of income.

(Millions of Dollars, except percentages)	For the Years Ended December 31, 2008	2007	2006
AFUDC:			
Borrowed funds	$17.8	$17.5	$13.5
Equity funds	29.0	17.4	13.6
Totals	$46.8	$34.9	$27.1
Average AFUDC rates	8.1%	7.6%	7.5%

The regulated companies' average AFUDC rate is based on a FERC-prescribed formula that produces 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 average eligible CWIP amounts to calculate AFUDC. Although AFUDC was recorded on 100 percent of CL&P's CWIP for its major transmission projects in southwest Connecticut, 50 percent of this AFUDC was 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. AFUDC is also recorded on 100 percent of CL&P's and WMECO's CWIP for their NEEWS projects, all of which is being reserved as a regulatory liability to reflect current rate base recovery for 100 percent of the CWIP as a result of FERC approved transmission incentives.

L. Sale of Customer Receivables

Prior to June 30, 2008, under the Receivables Purchase and Sale Agreement, CRC, a consolidated, wholly-owned subsidiary of CL&P, purchased an undivided interest in CL&P's accounts receivable and unbilled revenues and could sell up to $100 million thereof to a financial institution. At December 31, 2007, there were $20 million in such sales. On June 30, 2008, CL&P terminated the Receivables Purchase and Sale Agreement, and there are no receivables sold under that facility.

At December 31, 2007, amounts totaling $308.2 million sold to CRC by CL&P but not sold to the financial institution were included in investments in securitizable assets on the accompanying consolidated balance sheet. These amounts would have been excluded from CL&P's assets in the event of bankruptcy by CL&P. Since CL&P chose to terminate the Receivables Purchase and Sale Agreement on June 30, 2008, all such amounts are now included gross in accounts receivables and unbilled revenues on the accompanying consolidated balance sheet as of December 31, 2008 with $17.5 million of bad debt expense recorded in the provision for uncollectible accounts, which previously offset the investments in securitizable assets balance.

In 2007, the transfer of receivables to the financial institution under this arrangement qualified 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 and its subsidiaries implemented FIN 47 on December 31, 2005. FIN 47 requires an entity to recognize a liability for the fair value of an 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.

The fair value of the AROs is 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. Both the depreciation and accretion were recorded as increases to regulatory assets on the accompanying consolidated balance sheets at December 31, 2008 and 2007.

As 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, 2008 and 2007.

The following tables present the ARO asset, the related accumulated depreciation, the regulatory asset, and the ARO liabilities at December 31, 2008 and 2007:

	At December 31, 2008			
(Millions of Dollars)	ARO Asset	Accumulated Depreciation of ARO Asset	Regulatory Asset	ARO Liabilities
Asbestos	$ 2.7	$(1.6)	$20.7	$(22.6)
Hazardous contamination	5.1	(1.4)	15.2	(19.4)
Other AROs	4.0	(2.0)	6.4	(8.6)
Total AROs	$11.8	$(5.0)	$42.3	$(50.6)

	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 AROs	$14.0	$(5.8)	$40.6	$(49.7)

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

(Millions of Dollars)	2008	2007
Balance at beginning of year	$(49.7)	$(59.7)
Liabilities incurred during the year	(1.8)	(2.8)
Liabilities settled during the year	3.6	7.3
Accretion	(3.2)	(1.3)
Changes in estimates	-	7.9
Revisions in estimated cash flows	0.5	(1.1)
Balance at end of year	$(50.6)	$(49.7)

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. Fuel, Materials and Supplies

Fuel, materials and supplies include natural gas storage, coal, oil and materials purchased primarily for construction or operation and maintenance (O&M) purposes. Natural gas inventory, coal and oil are valued at the weighted average cost of gas, coal and oil. 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 and Counterparty Deposits

To the extent Select Energy requires collateral from counterparties, or the counterparties require collateral from Select Energy, cash is held on deposit by Select Energy or with unaffiliated counterparties and brokerage firms as a part of the total collateral required based on Select Energy's position in transactions with the counterparty. 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.

NU and its subsidiaries record special deposits and counterparty deposits in accordance with FSP FIN 39-1, "Amendment of FASB Interpretation No. 39," which requires NU to net collateral amounts posted under a master netting agreement if the related derivatives are recorded in a net position. At December 31, 2008, NU and its subsidiaries had no special deposits or counterparty collateral posted under master netting agreements that would be required to be netted against the fair value of derivatives.

Special deposits paid by Select Energy to unaffiliated counterparties and brokerage firms were not subject to master netting agreements and totaled $26.3 million and $18.9 million at December 31, 2008 and 2007, respectively. These amounts are recorded as current assets and are included in prepayments and other on the accompanying consolidated balance sheets. There were no counterparty deposits for Select Energy as of December 31, 2008 and 2007.

NU has established credit policies regarding counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties financial condition, collateral requirements and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. These evaluations result in established credit limits prior to entering into a contract. At December 31, 2008 and 2007, there were no counterparty deposits.

NU had amounts on deposit related to four subsidiaries used to facilitate the issuance of RRBs. These amounts totaled $41.3 million and $43.5 million at December 31, 2008 and 2007, respectively. In addition, NU had $7 million and $6.4 million in other cash deposits held with unaffiliated parties at December 31, 2008 and 2007, respectively. 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 CL&P and Yankee Gas 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, 2008, 2007, and 2006, gross receipts taxes, franchise taxes and other excise taxes of $126.6 million, $112.2 million, and $114.1 million, respectively, were included in operating revenues and taxes other than income taxes on the accompanying consolidated statements of income.

Certain sales taxes are also collected by CL&P and Yankee Gas 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.

R. Other Income, Net

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

	For the Years Ended December 31,		
(Millions of Dollars)	**2008**	**2007**	**2006**
Other Income:			
Investment income	$ 6.6	$ 22.3	$ 24.9
2008 federal tax settlement - interest	10.1	-	-
AFUDC - equity funds	29.0	17.4	13.6
Energy Independence Act incentives	12.1	9.9	5.5
Conservation and load management incentives	4.8	7.7	6.5
CL&P fixed procurement fee	-	-	11.0
Equity in earnings of regional nuclear generating and transmission companies	1.6	4.0	0.3
Gain on sale of Globix investment	-	-	3.1
Other	1.1	1.0	0.8
Total Other Income	65.3	62.3	65.7
Other Loss:			
Investment write-downs	(14.6)	(0.5)	-
Loss on investment in receivables	-	-	(1.1)
Other	(0.3)	(0.2)	(0.2)
Total Other Loss	(14.9)	(0.7)	(1.3)
Total Other Income, Net	$ 50.4	$ 61.6	$ 64.4

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

The CL&P fixed 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.

For further information regarding interest from the 2008 federal tax settlement, see Note 1H, "Summary of Significant Accounting Policies - Income Taxes," to the consolidated financial statements.

S. Supplemental Cash Flow Information

(Millions of Dollars)	For the Years Ended December 31, 2008	2007	2006
Cash paid (received) during the year for:			
Interest, net of amounts capitalized	$261.4	$261.6	$277.2
Income taxes	(36.1)	496.2	51.3
Non-cash investing activities:			
Capital expenditures incurred but not paid	132.8	184.4	105.2

Cash paid during the year for income taxes increased from 2006 to 2007 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.

Regulatory (refunds and underrecoveries)/overrecoveries on the accompanying consolidated statements of cash flows represents the year-over-year change in regulatory assets and regulatory liabilities, net of amortization charged during the year and other adjustments for non-cash items. These deferred amounts are expected to be recovered from or refunded to customers through the rate-making process.

T. Operating Expenses

Fuel, purchased and net interchange power: For the years ended December 31, 2008, 2007, and 2006, fuel, purchased and net interchange power included costs related to fuel of $541.7 million, $524.1 million, and $492.2 million, respectively, which include gas costs from our gas distribution segment of $358.8 million, 317.7 million and $291.3 million, respectively.

Other operating expenses: For the years ended December 31, 2008, 2007 and 2006, the majority of the other operating expenses were for general and administrative employee salaries, NUSCO's salary expenses, and conservation and load management customer assistance costs.

U. Marketable Securities

Supplemental benefit trust and spent nuclear fuel trust: NU maintains a supplemental benefit trust and a spent nuclear fuel trust, both of which 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, 2008, changes in the fair value of securities in the supplemental benefit trust relating to unrealized losses are considered other than temporary because NU does not have the ability to hold the securities to maturity and are 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 supplemental benefit trust are included in other income, net, on the consolidated statements of income. Realized gains, net of realized and unrealized losses associated with the spent nuclear fuel trust are recorded as an offset to the spent nuclear fuel trust obligation.

These trusts are not subject to regulatory oversight by state or federal agencies.

For information regarding marketable securities, see Note 9, "Marketable Securities," to the consolidated financial statements.

V. 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 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, 2008, CL&P and Yankee Gas had uncollectible hardship accounts receivable reserves in the amount of $41 million and $10 million, respectively, with the corresponding bad debt expense recorded as regulatory assets as these amounts are probable of recovery. At December 31, 2007, these amounts totaled $24 million and $8 million, respectively. For the year ended December 31, 2008, the CL&P and Yankee Gas reserves offset receivables. For the year ended December 31, 2007, the reserve offset amounts sold to CRC by CL&P but not sold to the financial institution. These amounts were classified as investments in securitizable assets on the accompanying consolidated balance sheets. For the year ended December 31, 2007, Yankee Gas reserves offset receivables.

W. Self-Insurance Accruals

NU is self-insured for employee medical coverage, long-term disability coverage and general liability coverage and up to certain limits for workers compensation coverage. Liabilities for insurance claims include accruals of estimated settlements for known claims, as well as accruals of estimates of incurred but not reported claims. These accruals are included in deferred credits and other liabilities - other on the accompanying consolidated balance sheets. In estimating these costs, NU considers historical loss experience and makes judgments about the expected levels of costs per claim. These claims are accounted for based on estimates of the undiscounted claims, including those claims incurred but not reported.

X. Related Parties

Several wholly-owned subsidiaries of NU provide support services for NU and its subsidiaries. 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, NU and its subsidiaries made aggregate discretionary contributions of $3 million to the NU Foundation (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. In 2008, NU and its subsidiaries did not make any contributions. 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.

2. Short-Term Debt

Limits: The amount of short-term borrowings that may be incurred by the regulated 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 system money pools from active regulation.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant. In an order dated August 3, 2007, the NHPUC increased the amount of short-term borrowings authorized for PSNH to a maximum of 10 percent of net fixed plant plus $35 million through the earlier of December 31, 2008, or until PSNH utilized its long-term debt authorization. At December 31, 2008, after the expiration of this additional authority, PSNH's short-term debt authorization under the 10 percent of net fixed plant test totaled $146.6 million. As a result of the NHPUC having jurisdiction over PSNH's

short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur. In November 2003, CL&P obtained from its preferred stockholders authorization for a ten-year period expiring in March 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 preferred stock provisions, provided that all unsecured indebtedness does not exceed 20 percent of total capitalization. As of December 31, 2008, CL&P was permitted to incur $584.4 million of additional unsecured debt under this authorization.

Yankee Gas is not required to obtain approval from any state or federal authority to incur short-term debt.

Regulated Companies Credit Agreement: CL&P, PSNH, WMECO, and Yankee Gas are parties to a five-year unsecured revolving credit facility in the nominal amount of $400 million that 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. There were $188 million, $45.2 million, $29.9 million and $52.3 million in short-term borrowings by CL&P, PSNH, WMECO and Yankee Gas, respectively, outstanding under this facility as of December 31, 2008. 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 on December 31, 2008 and 2007 was 3.35 percent and 7.25 percent, respectively.

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, 2008, NU had $303.5 million in short-term borrowings outstanding under this facility. At December 31, 2007, there were $42 million in short-term borrowings outstanding under this facility. The weighted-average interest rate on such borrowings outstanding under these credit agreements on December 31, 2008 and 2007 was 3.35 percent and 7.25 percent, respectively. There were $87 million and $27 million in LOCs outstanding at December 31, 2008 and 2007, respectively.

Under the regulated companies and NU parent credit agreements, NU and the regulated companies may borrow at prime rates or 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.

A participating lender in both agreements, Lehman Brothers Commercial Bank, has declined to fund on its remaining aggregate $55 million commitment since September 2008. At December 31, 2008, $23.5 million of this commitment remained outstanding from prior borrowings.

In addition, NU and the regulated companies must comply with certain financial and non-financial covenants, including a consolidated debt to capitalization ratio. NU and the regulated companies are in compliance with these covenants at December 31, 2008. If NU or the regulated companies were not in compliance with these covenants, they would not be allowed to borrow on the revolving credit agreements.

Amounts outstanding under these credit facilities, excluding the $45 million of long-term borrowings by Yankee Gas at December 31, 2007, 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.

3. 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 hedged items affect earnings, when hedge ineffectiveness is measured and recorded, or when the forecasted transaction being hedged is improbable 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 fair value of the company's derivative contracts may not represent amounts that will be realized. For further information on the fair value of derivative contracts, see Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," and Note 4, "Fair Value Measurements," to the consolidated financial statements. On the accompanying consolidated balance sheets at December 31, 2008 and 2007, these amounts are recorded as current or long-term derivative assets or liabilities and are summarized as follows:

	At December 31, 2008				
	Assets		Liabilities		
(Millions of Dollars)	Current	Long-Term	Current	Long-Term	Net Total
NU Enterprises:					
Wholesale	$ -	$ -	$ (14.5)	$ (49.4)	$ (63.9)
Regulated Companies - Gas:					
Supply	-	1.9	(0.2)	-	1.7
Regulated Companies - Electric:					
Supply/Stranded Costs	31.4	219.1	(86.2)	(863.0)	(698.7)
NU Parent:					
Interest Rate Hedging	-	20.8	-	-	20.8
Totals	$ 31.4	$241.8	$ (100.9)	$ (912.4)	$(740.1)

	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

For the regulated companies, except for 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.

The business activities of NU Enterprises that result in the recognition of derivative assets also create exposures to credit risk of energy marketing and trading counterparties. At December 31, 2008, Select Energy had no derivative assets from wholesale activities that are exposed to counterparty credit risk. The business activities of the regulated companies that resulted in the recognition of derivative assets also create exposure to various counterparties. At December 31, 2008, NU consolidated had $273.2 million of regulated company and NU parent derivative assets exposed to counterparty credit risk that are contracted with multiple entities, of which $125.5 million is contracted with investment grade entities, $4.6 million is contracted with a government-backed entity, $131.4 million is contracted with a non-rated subsidiary of an investment grade company and the remainder are contracted with multiple other counterparties.

NU Enterprises - Wholesale: Certain electric derivative contracts are part of NU Enterprises' remaining wholesale marketing business. These contracts include short-term and long-term electric supply contracts 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. A portion of the contract's fair value is determined based upon a model. The model utilizes natural gas prices and a heat rate conversion factor to determine off-peak electricity prices for one New York routinely quoted hub zone for 2013. For the balance of the hub zones, broker quotes for electricity are generally available on-peak through 2013 and off-peak through 2012.

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, 2008, 2007 and 2006, NU recorded a pre-tax benefit of $7 million and pre-tax charges of $7.4 million and $11.7 million, respectively, in fuel, purchased and net interchange power related to these contracts. In addition, 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.

Regulated Companies - Gas - Supply: Yankee Gas' 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/asset was recorded for these amounts as management believes that these costs will be refunded or recovered in rates.

Regulated Companies - Gas - Interest Rate Hedging: Yankee Gas had a forward interest rate swap agreement to hedge the interest cash outflows associated with its $100 million debt issuance in October 2008. The interest rate swap was based on a 10-year LIBOR swap rate and matched the index used for the debt issuance. As a cash flow hedge, the fair value of the hedge was recorded as a derivative asset on the accompanying consolidated balance sheets as of December 31, 2007, with an offsetting amount, net of tax, included in accumulated other comprehensive income. The swap was terminated in September 2008.

Regulated Companies - Electric - Supply/Stranded Costs: CL&P has contracts with two IPPs 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, 2008 included short-term and long-term derivative assets with fair values of $20.8 million and $110.6 million, respectively, and short-term and long-term derivative liabilities with fair values of $6.5 million and $65.6 million, respectively. 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, 2007, the fair values of these derivatives included short-term and long-term derivative assets with fair values of $53.3 million and $257.9 million, respectively, and short-term and long-term derivative liabilities with fair values of $2.9 million and $28.9 million, respectively.

CL&P has entered into FTR contracts and bilateral basis swaps to limit the congestion costs associated with its standard offer contracts. At December 31, 2008, the fair value of these contracts were recorded as a short-term derivative asset of $9.7 million, with an offset of $9.5 million recorded as a payable and included in other current liabilities and $0.2 million related to the mark-to-market adjustment recorded as a regulatory liability on the accompanying consolidated balance sheets. In addition, the fair value of the bilateral agreements has been recorded as a short-term derivative liability of $2.3 million with a $2.1 million offset to regulatory assets, net of the $0.2 million regulatory liability described above. Management believes that these costs will continue to be recovered or refunded in cost of service rates. At December 31, 2007, the fair value of these contracts was recorded as a short-term derivative asset of $1.4 million and a short-term derivative liability of $1.3 million on the accompanying consolidated balance sheets.

Pursuant to Public Act 05-01, "An Act Concerning Energy Independence," in August 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 forward capacity market price that the projects receive in the ISO-NE capacity markets for periods of up to 15 years beginning in 2009. As directed by the DPUC, CL&P has an agreement with UI under which it will share the costs and benefits of these four CfDs, with 80 percent allocated 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. At December 31, 2008, the fair value of the CL&P CfDs was recorded as a long-term derivative liability of $782.5 million. The fair values of UI's share of CL&P's contracts and CL&P's share of UI's contracts were recorded as a long-term derivative asset of $104.7 million.

An offsetting regulatory asset of $677.8 million was recorded, as management believes these amounts will be recovered from or refunded to customers in cost-of-service, regulated rates. The value of CL&P's CfDs at December 31, 2008 included approximately $100 million of initial gains and losses, previously deferred due to the use of significant unobservable inputs in the valuation, that were recorded upon adoption of SFAS No. 157 on January 1, 2008. At December 31, 2007, changes in CfD fair values since inception were recorded as a long-term derivative liability of $107.1 million, and UI's share and one CL&P CfD were recorded as long-term derivative assets of $20.8 million. Offsetting regulatory assets of $86.7 million and regulatory liabilities of $0.4 million were also recorded at December 31, 2007. A 2007 NRG Energy, Inc. (NRG) appeal of the DPUC's decision selecting the CfDs was taken into consideration in valuing the CfDs as of December 31, 2007, reducing the net negative derivative values by approximately $215 million. In February 2008, the appeal was denied, which increased derivative liabilities in 2008.

PSNH has electricity procurement contracts that are derivatives. The fair values of these contracts are calculated based on market prices and were recorded as short-term and long-term derivative liabilities totaling $76.8 million and $14.9 million, respectively, at December 31, 2008. At December 31, 2007, the fair value was recorded as a short-term derivative asset of $1.5 million and a short-term derivative liability of $2.5 million. An offsetting regulatory asset/liability was recorded as management believes that these costs will be recovered/refunded in rates as the energy is delivered.

PSNH has a contract to assign its transmission rights in a direct current transmission line in exchange for two energy call options that 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 option value modeling. At December 31, 2008, the options were recorded as a short-term and long-term derivative asset of $0.8 million and $3.8 million, respectively, which include mark-to-market losses of $11.1 million in 2008. The initial gain of $13.5 million on this transaction was recorded as a derivative asset and regulatory liability. Short-term and long-term derivative assets at December 31, 2007 were $3.6 million and $12.1 million, respectively, which include $2.2 million in mark-to-market gains in 2007. An offsetting regulatory liability was recorded, as management believes the benefit of this arrangement will be refunded to customers in rates.

PSNH has entered into FTR contracts to limit the congestion costs associated with its delivery service. At December 31, 2008, the FTRs were recorded as a short-term derivative asset of $0.1 million and a short-term derivative liability of $0.6 million. Offsetting these amounts are a payable and receivable to the ISO-NE of $0.1 million and $0.2 million, respectively, related to the initial auction price of the FTRs and a regulatory asset of $0.4 million related to the mark-to-market of the FTR. Management believes that these costs will continue to be recovered or refunded in cost-of-service rates. There were no similar amounts for 2007.

Regulated Companies - Electric - Interest Rate Hedging: At December 31, 2007, CL&P had two forward interest rate swap agreements to hedge the interest cash outflows associated with its debt issuance of $300 million in May 2008. PSNH had a forward interest rate swap agreement to hedge the interest cash outflows associated with its debt issuance of $110 million in May 2008. Prior to termination in May 2008, the interest rate swaps were based on a 10-year LIBOR swap rate and matched the index used for the debt issuances. As cash flow hedges, the fair values of these hedges were recorded as derivative assets at December 31, 2007 on the accompanying consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

NU Parent - Interest Rate Hedging: In March 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 senior notes that mature 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 statements of income. The cumulative change in the fair value of the swap and the long-term debt was recorded as a derivative asset and an increase to long-term debt of $20.8 million and $4.2 million at December 31, 2008 and 2007, respectively.

NU parent had a forward interest rate swap agreement to hedge the interest cash outflows associated with its planned debt issuance in June 2008. Prior to termination in June 2008, the interest rate swap was based on a 5-year LIBOR swap rate and a notional amount of $200 million, and matched the index used for the debt issuance. As a cash flow hedge at December 31, 2007, the fair value of the hedge was recorded as a $0.9 million derivative asset on the accompanying consolidated balance sheet with an offsetting amount, net of tax, included in accumulated other comprehensive income.

4. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis: The company's assets and liabilities recorded at fair value on a recurring basis have been categorized based upon the fair value hierarchy in accordance with SFAS No. 157. See Note 1F, "Summary of Significant Accounting Policies - Fair Value Measurements," for further information regarding the hierarchy and fair value measurements.

The following table presents the amounts of assets and liabilities carried at fair value at December 31, 2008 by the level in which they are classified within the SFAS No. 157 valuation hierarchy:

(Millions of Dollars)	
Derivative Assets:	
Level 1	$ -
Level 2	20.8
Level 3	252.4
Total	$ 273.2
Derivative Liabilities:	
Level 1	$ -
Level 2	(91.7)
Level 3	(921.6)
Total	$(1,013.3)
Marketable Securities:	
Level 1	$ 42.1
Level 2	67.1
Level 3	-
Total	$ 109.2

Not included in the table above are $81.6 million of cash equivalents held by NU parent in an unrestricted money market account and included in cash and cash equivalents on the accompanying consolidated balance sheet, which are classified as Level 1 in the fair value hierarchy.

The following table presents changes for the year ended December 31, 2008 in the Level 3 category of assets and liabilities measured at fair value on a recurring basis. This category includes derivative assets and liabilities, which are presented net. The derivative amounts at January 1, 2008 reflect the fair values after initial adoption of SFAS No. 157. The company classifies assets and liabilities in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model. In addition to these unobservable inputs, the valuation models for Level 3 assets and liabilities typically also rely on a number of inputs that are observable either directly or indirectly. Thus, the gains and losses presented below include changes in fair value that are attributable to both observable and unobservable inputs. There were no transfers into or out of Level 3 assets and liabilities for the year ended December 31, 2008:

(Millions of Dollars)	
Derivatives, Net:	
Fair value at January 1, 2008 [1]	$ (511.1)
Net realized/unrealized gains included in:	
Earnings [2]	12.0
Regulatory assets/liabilities	(138.0)
Purchases, issuances and settlements	(32.1)
Fair value at December 31, 2008	$ (669.2)
Period change in unrealized gains included in earnings relating to items held at December 31, 2008	$ 7.0

(1) Amounts as of January 1, 2008 reflect fair values after initial adoption of SFAS No. 157. As a result of implementing SFAS No. 157, the company recorded an increase to derivative liabilities and a pre-tax charge to earnings of $6.1 million as of January 1, 2008 related to NU Enterprises' remaining derivative contracts. The company also recorded changes in fair value of CL&P's CfD and IPP contracts, resulting in increases to derivative liabilities of approximately $590 million, with an offset to regulatory assets and a decrease to derivative assets of approximately $30 million with an offset to regulatory liabilities.

(2) Realized and unrealized gains and losses on derivatives included in earnings relate to the remaining Select Energy wholesale marketing contracts and are reported in fuel, purchased and net interchange power on the accompanying consolidated statements of income.

5. 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 on the consolidated balance sheets, based on the difference between the projected benefit obligation (PBO) for the Pension Plan and accumulated postretirement benefit obligation (APBO) for the PBOP Plan and the fair value of plan assets. At December 31, 2008, the fair values of plan assets are measured in accordance with SFAS No. 157. 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, 2008 and 2007, NU recorded an after-tax charge/(benefit) totaling $38 million and $(8.6) 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 $1.1 billion and $201.4 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 sponsors a single uniform noncontributory defined benefit retirement plan (Pension Plan) under ERISA covering substantially all regular employees of NU and its subsidiaries. Benefits are based on years of service and the employees' highest eligible compensation during 60 consecutive months of employment. NU allocates net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked by the trustee for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year. NU uses a December 31st measurement date for the Pension Plan. Pension expense affecting earnings is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2008	2007	2006
Total pension expense	$2.4	$17.1	$50.2
Income/(expense) capitalized as utility plant	4.9	1.0	(11.5)
Total pension expense, net of amounts capitalized	$7.3	$18.1	$38.7

Pension Curtailments and Termination Benefits: In December 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 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. 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.

Actuarial Determination of Expense: Pension and PBOP expense consists of the service cost and prior service cost determined by actuaries, the interest cost based on the discounting of the obligations and the amortization of the net transition obligation, offset by the expected return on plan assets. Pension and PBOP expense also includes amortization of actuarial gains and losses, which represent differences between assumptions and actual or updated information.

The expected return on plan assets is calculated by applying the assumed rate of return to a four-year rolling average of plan asset fair values, which reduces year-to-year volatility. This 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 calculated expected return and the actual return based on the change in the fair value of assets during the year. As investment gains and losses are reflected in the average plan asset fair values, they are subject to amortization with other unrecognized gains/losses. Unrecognized gains/losses are amortized as a component of pension and PBOP expense over approximately 12 years, which is the average future service period of the employees at December 31, 2008.

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. NU allocates net periodic SERP benefit costs to its subsidiaries based upon actuarial calculations by participant.

Although the company maintains a trust to support the SERP with marketable securities held in the supplemental benefit trust, the plan itself does not contain any assets. For information regarding the investments in the supplemental benefit trust that are used to support the SERP liability, see Note 9 "Marketable Securities," to the consolidated financial statements.

PBOP Plan: NU provides certain retiree 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.

NU allocates net periodic postretirement benefits expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. Benefit payments to participants and contributions are also tracked for each subsidiary. The actual investment return for the trust each year is allocated to each of the subsidiaries in proportion to the investment return expected to be earned during the year.

PBOP Curtailments and Termination Benefits: NU recorded an estimated pre-tax curtailment expense in 2005 relating to its corporate reorganization. NU also accrued a pre-tax termination benefit in 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 benefit obligations for NU's plans, fair values of plan assets, and funded status:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Change in benefit obligation						
Benefit obligation at beginning of year	$ (2,256.9)	$ (2,334.6)	$ (32.1)	$ (34.0)	$ (459.6)	$ (469.9)
Service cost	(43.9)	(47.0)	(0.7)	(0.8)	(7.1)	(7.4)
Interest cost	(144.0)	(136.4)	(2.0)	(1.9)	(28.3)	(25.7)
Actuarial gain/(loss)	19.5	178.4	(1.7)	2.6	20.2	3.3
Prior service cost	-	(40.0)	-	-	-	-
Federal subsidy on benefits paid	-	-	-	-	(3.4)	(3.8)
Benefits paid - excluding lump sum payments	127.1	122.2	2.3	2.0	42.2	43.9
Benefits paid - lump sum payments	0.5	0.2	-	-	-	-
Termination benefits	-	0.3	-	-	-	-
Benefit obligation at end of year	$ (2,297.7)	$ (2,256.9)	$ (34.2)	$ (32.1)	$ (436.0)	$ (459.6)
Change in plan assets						
Fair value of plan assets at beginning of year	$ 2,459.4	$ 2,356.2	$ N/A	$ N/A	$ 278.1	$ 266.6
Actual return on plan assets	(775.0)	225.6	N/A	N/A	(80.1)	14.4
Employer contribution	-	-	N/A	N/A	39.8	41.0
Benefits paid - excluding lump sum payments	(127.1)	(122.2)	N/A	N/A	(42.2)	(43.9)
Benefits paid - lump sum payments	(0.5)	(0.2)	N/A	N/A	-	-
Fair value of plan assets at end of year	$ 1,556.8	$ 2,459.4	N/A	N/A	$ 195.6	$ 278.1
Funded status at December 31st	$ (740.9)	$ 202.5	$ (34.2)	$ (32.1)	$ (240.4)	$ (181.5)

The amounts recognized on the accompanying consolidated balance sheets for the funded status above at December 31, 2008 and 2007 is as follows:

	At December 31,					
	Pension Benefits		SERP Benefits		Postretirement Benefits	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
(Accrued)/prepaid pension	$(740.9)	$202.5	$ -	$ -	$ -	$ -
Other current liabilities	-	-	(2.3)	(2.4)	-	-
Other deferred credits and other liabilities	-	-	(31.9)	(29.7)	-	-
Accrued postretirement benefits	-	-	-	-	(240.4)	(181.5)

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 gain/(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 gain/(loss) over the remaining service lives of its employees as calculated on an individual operating company basis.

The accumulated benefit obligation for the Pension Plan was $2 billion at December 31, 2008 and 2007 and was $32.1 million and $30.2 million for the SERP at December 31, 2008 and 2007, respectively.

The following is a summary of amounts recorded as regulatory assets as a result of SFAS No. 158 at December 31, 2008 and 2007 and the changes in those amounts recorded during the years:

	At December 31,					
	Pension		SERP		PBOP	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Transition obligation at beginning of year	$ 0.5	$ 0.7	$ -	$ -	$ 56.6	$ 67.9
Amounts reclassified as net periodic benefit expense	(0.2)	(0.2)	-	-	(11.3)	(11.3)
Transition obligation at end of year	$ 0.3	$ 0.5	$ -	$ -	$ 45.3	$ 56.6
Prior service cost at beginning of year	$ 67.2	$ 38.1	$ 0.5	$ 0.6	$ (3.6)	$ (3.9)
Amounts reclassified as net periodic benefit (expense)/income	(9.6)	(8.6)	(0.1)	(0.1)	0.3	0.3
Prior service cost arising during the year	0.2	37.7	-	-	-	-
Prior service cost at end of year	$ 57.8	$ 67.2	$ 0.4	$ 0.5	$ (3.3)	$ (3.6)
Net actuarial (gains)/losses at beginning of year	$ (24.2)	$ 184.7	$ 1.8	$ 5.0	$ 102.6	$ 114.3
Amounts reclassified as net periodic benefit expense	(5.6)	(19.9)	(0.2)	(0.6)	(10.4)	(12.0)
Actuarial losses/(gains) arising during the year	897.0	(189.0)	1.6	(2.6)	77.8	0.3
Actuarial losses/(gains) at end of year	$ 867.2	$ (24.2)	$ 3.2	$ 1.8	$ 170.0	$ 102.6
Total deferred benefit costs as regulatory assets	$ 925.3	$ 43.5	$ 3.6	$ 2.3	$ 212.0	$ 155.6

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2009 are as follows:

	Estimated Expense in 2009		
(Millions of Dollars)	Pension	SERP	PBOP
Transition obligation	$ 0.3	$ -	$11.3
Prior service cost	9.5	0.1	0.3
Net actuarial loss	20.6	0.5	9.8
Total	$30.4	$0.6	$21.4

The following is a summary of amounts recorded in accumulated other comprehensive income, as a result of SFAS No. 158 at December 31, 2008 and 2007 and the changes in those amounts recorded to other comprehensive income:

	At December 31,					
	Pension		SERP		PBOP	
(Millions of Dollars)	2008	2007	2008	2007	2008	2007
Transition obligation at beginning of year	$ -	$ -	$ -	$ -	$1.2	$1.5
Amounts reclassified as net periodic benefit expense	-	-	-	-	(0.3)	(0.3)
Transition obligation at end of year	$ -	$ -	$ -	$ -	$0.9	$1.2
Prior service cost at beginning of year	$ 2.7	$ 0.6	$ -	$ -	$ -	$ -
Amounts reclassified as net periodic benefit expense	(0.3)	(0.2)	-	-	-	-
Prior service (credit)/cost arising during the year	(0.3)	2.3	-	-	-	-
Prior service cost at end of year	$ 2.1	$ 2.7	$ -	$ -	$ -	$ -
Net actuarial (gains)/losses at beginning of year	$(17.4)	$ 2.6	$0.2	$0.3	$5.5	$5.5
Amounts reclassified as net periodic benefit income/(expense)	0.9	(0.2)	-	-	(0.2)	(0.3)
Actuarial losses/(gains) arising during the year	58.9	(19.8)	(0.1)	(0.1)	3.5	0.3
Actuarial losses/(gains) at end of year	$ 42.4	$(17.4)	$0.1	$0.2	$8.8	$5.5
Total Pension, SERP and PBOP in accumulated other comprehensive income	$44.5	$(14.7)	$0.1	$0.2	$9.7	$6.7

The estimates of the above amounts that are expected to be recognized as portions of net periodic benefit expense in 2009 are as follows:

	Estimated Expense in 2009		
(Millions of Dollars)	Pension	SERP	PBOP
Transition obligation	$ -	$-	$0.2
Prior service cost	0.3	-	-
Net actuarial loss	-	-	0.2
Total	$0.3	$-	$0.4

For further information, see Note 13, "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	2008	2007	2008	2007
Discount rate	6.89%	6.60%	6.90%	6.35%
Compensation/progression rate	4.00%	4.00%	N/A	N/A
Health care cost trend rate	N/A	N/A	8.00%	8.50%

The components of net periodic benefit expense/(income) are as follows:

	For the Years Ended December 31,								
	Pension Benefits			SERP Benefits			Postretirement Benefits		
(Millions of Dollars)	2008	2007	2006	2008	2007	2006	2008	2007	2006
Service cost	$43.9	$47.0	$49.4	$0.7	$0.8	$1.1	$ 7.1	$ 7.4	$ 8.3
Interest cost	144.0	136.4	129.7	2.0	1.9	1.9	28.3	25.7	27.3
Expected return on plan assets	(200.2)	(195.2)	(174.0)	-	-	-	(21.1)	(18.2)	(14.0)
Net transition obligation cost/(asset)	0.2	0.2	(0.1)	-	-	-	11.6	11.6	11.6
Prior service cost/(credit)	9.9	8.9	6.6	0.1	0.2	0.2	(0.3)	(0.3)	(0.3)
Actuarial loss	4.6	20.1	41.1	0.3	0.7	0.9	10.6	12.2	17.8
Net periodic expense - before curtailments and termination (benefits)/expense	2.4	17.4	52.7	3.1	3.6	4.1	36.2	38.4	50.7
Curtailment benefits	-	-	(4.8)	-	-	-	-	-	(2.2)
Termination (benefits)/expense	-	(0.3)	2.3	-	-	-	-	-	0.3
Total curtailments and termination benefits	-	(0.3)	(2.5)	-	-	-	-	-	(1.9)
Total - net periodic expense	$ 2.4	$17.1	$50.2	$3.1	$3.6	$4.1	$36.2	$38.4	$48.8

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	2008	2007	2006	2008	2007	2006
Discount rate	6.60%	5.95%(1)	5.80%	6.35%	5.80%	5.65%
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,	
	2008	2007
Health care cost trend rate assumed for next year	8.00%	8.50%
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	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	11.4	(10.0)

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 over 11 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	
	2008 and 2007		2008 and 2007	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:				
United States	40%	9.25%	55%	9.25%
Non-United States	17%	9.25%	11%	9.25%
Emerging markets	5%	10.25%	2%	10.25%
Private	8%	14.25%	-	-
Debt Securities:				
Fixed income	25%	5.50%	27%	5.50%
High yield fixed income	-	-	5%	7.50%
Real Estate	5%	7.50%	-	-

The actual asset allocations at December 31, 2008 and 2007 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	
	2008	2007	2008	2007
Equity Securities:				
United States	34%	40%	57%	55%
Non-United States	16%	17%	12%	14%
Emerging markets	4%	5%	1%	1%
Private	11%	7%	-	-
Debt Securities:				
Fixed income	29%	26%	29%	29%
High yield fixed income	-	-	1%	1%
Real Estate	6%	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)	Pension Benefits	SERP Benefits	Postretirement Benefits	Goverment Benefits
2009	$124.1	$2.3	$43.2	$(3.9)
2010	128.9	2.5	43.9	(4.2)
2011	132.4	2.7	44.2	(4.6)
2012	136.0	2.9	44.3	(5.0)
2013	140.8	3.1	44.6	(5.3)
2014-2018	805.1	17.4	224.8	(31.3)

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 an amount that will satisfy the requirements of the Employee Retirement Income Security Act and Internal Revenue Code. NU's Pension Plan has historically been well funded, and a contribution has not been required to be made to the plan since 1991. Due to the underfunded balance at December 31, 2008, NU is required to make a contribution to the plan of approximately $150 million to meet current minimum funding requirements. This contribution would be paid just prior to the 2009 federal income tax return filing in 2010.

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 $36.2 million for the year ended December 31, 2008 to fund the PBOP Plan and expects to make $37.3 million in contributions to the PBOP Plan in 2009. Beginning in 2007, NU made an additional contribution to the PBOP Plan for the amounts received from the federal Medicare subsidy. This amount was $3.7 million in 2008 and is estimated to be $3.4 million in 2009.

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 allocated from the Employee Stock Ownership Plan (ESOP). The 401(k) matching contributions of cash and NU common shares made by NU were $12 million in 2008, $10.7 million in 2007, and $11 million in 2006.

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 program under the 401(k) 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 $2 million in 2008, $1 million in 2007 and $0.1 million in 2006.

C. Employee Stock Ownership Plan

NU maintains an 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. Through December 31, 2008, NU made 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 $6 million in 2008, $4.2 million in 2007 and $8.2 million in 2006. Interest expense on the unsecured notes was $3.2 million in 2006. For the years ended December 31, 2008, 2007 and 2006, NU recognized $8 million, $6.9 million and $7.4 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 2005. The $175 million Series A note was fully repaid in December 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 2007, NU paid a $0.1875 per share quarterly dividend. During the third quarter of 2007 through the second quarter of 2008, NU paid a $0.20 per share quarterly dividend. NU paid a $0.2125 per share dividend during the third and fourth quarters of 2008.

In 2008 and 2007, the ESOP trust allocated 469,601 and 363,470 of NU common shares, respectively, to satisfy 401(k) Savings Plan obligations to employees. At December 31, 2008 and 2007, total allocated ESOP shares were 10,130,407 and 9,660,806, respectively, and total unallocated ESOP shares were 669,778 and 1,139,379, respectively. The fair market value of the unallocated ESOP shares at December 31, 2008 and 2007 was $16.1 million and $35.7 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 which NU employees and officers are entitled to participate. NU records compensation cost related to these plans, as applicable, for shares issued or sold to NU employees and officers. 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 consolidated financial statements and no effect on NU's EPS. For the years ended December 31, 2008 and 2007, tax expense in excess of compensation cost totaling $1.6 million and $3.2 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.

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, 2008 and 2007, NU had 2,705,615 and 3,055,083 of common shares, respectively, available for issuance under the Incentive Plan.

Restricted Shares: NU has granted restricted shares under the 2002 through 2004 incentive programs that are subject to three-year and four-year graded vesting schedules. The remaining restricted shares of 6,250, with a per share and total weighted average grant-date fair value of $18.65 and $0.1 million, respectively, were fully vested in February 2008. The per share and total weighted average grant-date fair value for restricted shares vested was $14.14 and $0.8 million, respectively, for the year ended December 31, 2007 and $14.52 and $1.1 million, respectively, for the year ended December 31, 2006.

The total compensation cost recognized for restricted shares was $12 thousand, net of taxes of approximately $8 thousand for the year ended December 31, 2008, $58 thousand, net of taxes of approximately $39 thousand for the year ended December 31, 2007, and $0.6 million, net of taxes of approximately $0.4 million for the year ended December 31, 2006.

RSUs: NU has granted RSUs under the 2004 through 2008 incentive programs that are subject to three-year and four-year graded vesting schedules for employees,

and one-year graded vesting schedules for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings, subsequent to vesting. A summary of RSU transactions for the year ended December 31, 2008 is as follows:

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, 2007	831,000	$22.99			
Granted	352,482	$26.82	$9.5		
Issued	(263,422)	$21.94	$5.8		
Forfeited	(7,069)	$25.97	$0.2		
Outstanding at December 31, 2008	912,991	$24.75	$22.6	$9.0	2.0

The per share and total weighted average grant date fair value for RSUs granted was $28.83 and $9.5 million, respectively, for the year ended December 31, 2007 and $19.87 and $7.4 million, respectively, for the year ended December 31, 2006. The weighted average grant-date fair value per share for RSUs issued was $19.77 and $18.50 for the years ended December 31, 2007 and 2006, respectively. The total weighted average fair value of RSUs issued was $3.2 million and $2.2 million for the years ended December 31, 2007 and 2006, respectively.

The total compensation cost recognized for RSUs was $3.9 million, net of taxes of approximately $2.6 million for the year ended December 31, 2008, $3.6 million, net of taxes of approximately $2.4 million for the year ended December 31, 2007 and $2.8 million, net of taxes of approximately $1.9 million for the year ended December 31, 2006.

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, 2008 is 2.4 years. A summary of stock option transactions is as follows:

		Exercise Price Per Share		
	Options	Range	Weighted Average	Intrinsic Value (Millions)
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	
Exercised	(76,260)		$16.2473	$0.6
Forfeited and cancelled	-		-	
Outstanding and exercisable - December 31, 2008	320,920	$14.9375-$21.0300	$18.8335	$1.7

Cash received for options exercised during the year ended December 31, 2008 totaled $1.2 million. The tax benefit realized from stock options exercised totaled $0.3 million for the year ended December 31, 2008.

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 2008 and 2007, employees purchased 31,250 and 26,451 shares, respectively, at discounted prices of $26.40 and $23.90 in 2008 and $26.27 and $25.97 in 2007. At December 31, 2008 and 2007, 1,010,114 and 1,041,364 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 $45.4 million and $46.4 million at December 31, 2008 and 2007, respectively. During 2008, 2007 and 2006, $3.8 million, $8.4 million and $5.6 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.”

6. 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. However, if an event occurs or circumstances change that would indicate that goodwill might be impaired, NU management would test the goodwill between the annual testing dates. 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, 2008 and 2007 is $287.6 million.

NU completed its impairment analysis of the Yankee Gas goodwill balance as of October 1, 2008 and determined that no impairment exists. In completing this analysis, the fair value of the reporting unit was estimated using a discounted cash flow methodology and analyses of comparable companies and transactions.

7. Commitments and Contingencies

A. Regulatory Developments and Rate Matters

Connecticut:
CTA and SBC Reconciliation: The CTA allows CL&P to recover stranded costs, such as securitization costs associated with its RRBs, amortization of regulatory assets, and IPP over-market costs, while the 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 worker protection costs.

On March 31, 2008, CL&P filed with the DPUC its 2007 CTA and SBC reconciliation, which compared CTA and SBC revenues to revenue requirements. For the 12 months ended December 31, 2007, total CTA revenues exceeded CTA revenue requirements by $26.1 million, which has been recorded as a decrease to the CTA regulatory asset on the accompanying consolidated balance sheet. For the 12 months ended December 31, 2007, the SBC cost of service exceeded SBC revenues by $39.4 million, which has been recorded as a regulatory asset on the accompanying consolidated balance sheet.

On December 3, 2008, the DPUC issued a final decision in this docket that approved the 2007 CTA and SBC reconciliations with minor modifications. The decision referred to a potential change in the CTA rate effective January 1, 2009, when new rates were to be determined for all CL&P rate components. By letter dated December 23, 2008, the DPUC approved CL&P's recommendation to slightly decrease the base CTA rate and to establish a separate CTA refund credit beginning January 1, 2009. The CTA refund credit is intended to return to customers over a twelve month period a projected 2008 CTA overrecovery of $46.2 million, plus $1.8 million of incremental distribution revenues attributable to accelerating CL&P's previously allowed 2009 distribution rate increase from a start date of February 1, 2009 to January 1, 2009. The DPUC also approved an increase in the SBC rate to bill an additional $11.7 million in 2009, which should enable CL&P to fully recover 2009 SBC expenses plus expenses that were underrecovered in prior periods.

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. In prior years, CL&P submitted to the DPUC its proposed methodology to calculate the variable incentive portion of its transition service procurement fee, which was effective through 2006, and requested approval of the pre-tax $5.8 million 2004 incentive fee. CL&P has not recorded amounts related to the 2005 or 2006 procurement fee in earnings. CL&P recovered the $5.8 million pre-tax amount, which was recorded in 2005 earnings through the CTA reconciliation process. On January 15, 2009, the DPUC issued a final decision confirming its December 2008 draft decision in this docket that reversed its December 2005 draft decision and stated that CL&P was not eligible for the procurement incentive compensation for 2004. A $5.8 million pre-tax charge was recorded in the 2008 earnings of CL&P, and an obligation to refund the $5.8 million to customers has been established as of December 31, 2008. CL&P filed an appeal of this decision on February 26, 2009.

C2 Prudency Audit: Pursuant to the decision in CL&P's 2007 rate case, the DPUC has hired a consulting firm to perform a prudency audit of certain costs incurred in the implementation of a new customer service system (C2) at CL&P. The audit began on December 1, 2008 and will be ongoing through early 2009, with a final report to the DPUC due March 31, 2009. The DPUC has stated its intentions to open a docket to review the findings of the audit after completion. Management continues to believe that its C2 expenses were prudent and will be recovered in rates.

Purchased Gas Adjustment: In 2005 and 2006, the DPUC issued decisions regarding Yankee Gas' PGA clause charges and required an audit of previously recovered PGA revenues of approximately $11 million associated with unbilled sales and revenue adjustments for the period of September 1, 2003 through August 31, 2005. On June 11, 2008, the DPUC issued a final order requiring Yankee Gas to refund approximately $5.8 million in previous recoveries to its customers. The $5.8 million pre-tax charge was recorded in the 2008 earnings of Yankee Gas.

New Hampshire:
ES and SCRC Reconciliation: On an annual basis, PSNH files with the NHPUC an ES and stranded cost recovery charge (SCRC) reconciliation filing for the preceding year. On May 1, 2008, PSNH filed its 2007 ES and SCRC reconciliation with the NHPUC, whose evaluation includes a prudence review of PSNH's generation activities. During 2007, ES and SCRC revenues exceeded ES and SCRC costs by $1.4 million and $6.8 million, respectively, and were deferred as a regulatory liability to be refunded to customers. On November 19, 2008, PSNH and the NHPUC Staff submitted a settlement agreement that resolved all outstanding issues. The NHPUC issued an order dated January 16, 2009 that accepted the settlement as filed. The settlement agreement and subsequent order did not have a material adverse impact on PSNH's financial position or results of operations.

Massachusetts:
Transition Cost Reconciliation: On July 18, 2008, WMECO filed its 2007 transition cost (TC) reconciliation with the DPU, which compared TC revenue and revenue requirements. For the twelve months ended December 31, 2007, total TC revenues along with carrying charges exceeded TC revenue requirements by $2.6 million, which has been recorded as a regulatory liability on the accompanying consolidated balance sheets. A public hearing and procedural conference was held on November 20, 2008. On December 22, 2008, the Massachusetts Attorney General filed testimony on two topics, the deferred return and carrying charges on the Capital Project Scheduling List and the recovery of Northeast Nuclear Company pension/PBOP costs. WMECO filed rebuttal testimony on December 30, 2008. A hearing was held January 29, 2009. The briefing period ended on February 26, 2009. There is no timeline for a DPU decision. Management does not expect the outcome of the DPU's review of this filing to have a material adverse effect on WMECO's financial position or results of operations.

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, 2008 and 2007, NU had $27.4 million and $25.8 million, respectively, recorded as environmental reserves. A table of the activity in these reserves at December 31, 2008 and 2007 is as follows:

(Millions of Dollars)

Balance at December 31, 2006	$26.8
Additions	1.2
Payments	(2.2)
Balance at December 31, 2007	25.8
Additions	4.6
Payments	(3.0)
Balance at December 31, 2008	$27.4

Of the 54 sites NU has currently included in the environmental reserve, 27 sites are in the remediation or long-term monitoring phase, 22 sites have had some level of site assessments completed, and the remaining 5 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. NU has not recorded any probable recoveries from third parties. The environmental reserve includes sites at different stages of discovery and remediation and does not include any unasserted claims.

At December 31, 2008, in addition to the 54 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.

HWP remains in the process of evaluating additional potential remediation requirements at a river site in Massachusetts containing tar deposits associated with a manufactured gas plant (MGP) site, which it sold to Holyoke Gas and Electric (HG&E), a municipal electric utility, in 1902. HWP is at least partially responsible for this site, and has already conducted substantial investigative and remediation activities. HWP first established a reserve for this site in 1994. A pre-tax charge of approximately $3 million was recorded in 2008 to reflect the estimated cost of further tar delineation and site characterization studies, as well as certain remediation costs that are considered to be probable and estimable as of December 31, 2008. The cumulative expense recorded to this reserve through December 31, 2008 was approximately $15.9 million, of which $13.9 million had been spent, leaving approximately $2 million in the reserve as of December 31, 2008.

The Massachusetts Department of Environmental Protection (MA DEP) issued a letter on April 3, 2008 to HWP and HG&E, which share responsibility for the site, providing conditional authorization for additional investigatory and risk characterization activities and providing detailed comments on HWP's 2007 reports and proposals for further investigations. MA DEP also indicated that further removal of tar in certain areas was necessary prior to commencing many of the additional studies and evaluation. This letter represents guidance from the MA DEP, rather than mandates. HWP has developed and begun to implement plans for additional investigations in conformity with MA DEP's guidance letter, including estimated costs and schedules. These matters are subject to ongoing discussions with MA DEP and HG&E and may change from time to time.

At this time, management believes that the $2 million remaining in the reserve is at the low end of a range of probable and estimable costs of approximately $2 million to $2.7 million and will be sufficient for HWP to conduct the additional tar delineation and site characterization studies, evaluate its approach to this matter and conduct certain soft tar remediation. The additional studies are expected to occur through 2009.

There are many outcomes that could affect management's estimates and require an increase to the reserve, or range of costs, and a reserve increase would be reflected as a charge to pre-tax earnings. However, management cannot reasonably estimate the range of additional investigation and remediation costs because they will depend on, among other things, the level and extent of the remaining tar that may be required to be remediated, 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. Further developments may require a material increase to this reserve.

HWP's share of the remediation costs related to this site is not recoverable from customers.

MGP Sites: MGP sites comprise the largest portion of the environmental liabilities. MGPs are sites that manufactured gas from coal that produced certain byproducts that may pose a risk to human health and the environment. At December 31, 2008 and 2007, $25.4 million and $23.6 million, respectively, represent amounts for the site assessment and remediation of MGPs. At December 31, 2008 and 2007, the 5 largest MGP sites comprise approximately 63 percent and 68 percent, respectively, of the total MGP environmental liability.

For 7 of the 54 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, 2008, $5.1 million had been accrued as a liability for these sites, which represent management's best estimates of the liabilities for environmental costs. These amounts are the best estimates within estimated ranges of losses from zero to $11 million. For the 47 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 54 sites, 5 are superfund sites under CERCLA for which the company has been notified that it is a potentially responsible party (PRP) but for which the site assessment and remediation are not being managed by the company. At December 31, 2008, a liability of $0.7 million accrued on these sites represents management's best estimate of its potential remediation costs with respect to these 5 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, 2008 and 2007, fees due to the DOE for the disposal of Prior Period Spent Nuclear Fuel for the year ended December 31, 2008 and 2007, respectively, are included in long-term debt and were $298.6 million and $294.3 million, respectively, including accumulated interest costs of $217.9 million and $212.6 million, respectively.

During 2004, WMECO established a trust that 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 9, "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, 2008 are as follows:

(Millions of Dollars)	2009	2010	2011	2012	2013	Thereafter	Totals
VYNPC	$ 30.3	$ 29.6	$ 30.2	$ 7.2	$ -	$ -	$ 97.3
Supply/stranded cost contracts	233.0	222.7	259.6	261.0	252.5	834.5	2,063.3
Renewable energy contracts	2.8	36.8	64.6	119.0	118.9	1,667.5	2,009.6
Peaker CfDs	-	5.2	15.0	21.6	20.8	35.5	98.1
Natural gas procurement contracts	58.5	58.3	57.3	50.5	27.0	122.9	374.5
Wood, coal and transportation contracts	141.5	87.6	82.5	56.1	-	-	367.7
PNGTS pipeline commitments	2.1	2.0	2.0	2.0	2.0	7.9	18.0
Hydro-Québec support commitments	20.2	20.5	20.6	20.3	19.9	136.5	238.0
Transmission segment project commitments	186.6	156.0	153.4	131.1	48.0	-	675.1
Yankee Companies billings	25.7	28.0	29.7	29.8	29.4	50.4	193.0
Clean air project commitments	76.3	75.3	36.3	16.4	5.1	-	209.4
Vehicle/equipment commitments	14.6	1.9	28.5	-	-	-	45.0
Totals	$791.6	$723.9	$779.7	$715.0	$523.6	$2,855.2	$6,389.0

VYNPC: CL&P, PSNH and WMECO have commitments to buy approximately 9.5 percent, 4 percent and 2.5 percent, respectively, of the Vermont Yankee Nuclear Power Corporation (VYNPC) plant's output through March 2012 at a range of fixed prices. The total cost of purchases under contracts with VYNPC amounted to $26.5 million in 2008, $25.6 million in 2007 and $32.2 million in 2006.

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 $237.6 million in 2008, $281.5 million in 2007 and $331.9 million in 2006. 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 information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI, are subject to changes in capacity prices that the projects receive in the ISO-NE capacity markets and CL&P's portion of the costs and benefits of these contracts 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 last resort service or WMECO's default service, both of which represent contractual commitments that are conditional upon CL&P and WMECO customers' use of energy, and PSNH's short-term power supply management.

Renewable Energy Contracts: CL&P has entered into various agreements to purchase energy, capacity and renewable energy credits from renewable energy facilities. Amounts payable under these contracts are subject to a sharing agreement with UI, whereby UI will share approximately 20 percent of the costs and benefits of these contracts. In addition, UI has entered into contracts that are subject to this cost sharing agreement under which CL&P will share in approximately 80 percent of the costs and benefits of the contract. The information in the table above includes 100 percent of the payments projected under the contracts entered into by CL&P and 80 percent of the payments projected under the contracts entered into by UI. CL&P's portion of the costs and benefits of these contracts will be paid by or refunded to CL&P's customers.

Peaker CfDs: In 2008, CL&P has entered into three CfDs with developers of peaking generation units approved by the DPUC (Peaker CfDs). These units will have a total of approximately 500 MW of peaking capacity. As directed by the DPUC, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the developer the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The information in the table above includes 100 percent of the estimated payments projected under the contracts, before reimbursement from UI under the sharing agreement. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant construction and operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from 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' procurement portfolio, including these contracts, amounted to $352.5 million in 2008, $305.3 million in 2007 and $275.1 million in 2006.

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 2009. PSNH's fuel and natural gas costs, excluding emissions allowances, amounted to approximately $165.4 million in 2008, $183.8 million in 2007 and $149.1 million in 2006.

PNGTS Pipeline Commitments: PSNH has a contract for capacity on the Portland Natural Gas Transmission System (PNGTS) pipeline that extends through 2018. The cost under this contract amounted to $1.5 million in 2008, $3.1 million in 2007 and $1.4 million in 2006. These costs are not recovered from PSNH's retail customers.

Hydro-Québec Support Commitments: Along with other New England utilities, CL&P, PSNH and WMECO have entered into agreements to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec 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 $18.3 million in 2008, $18.8 million in 2007, and $20.5 million in 2006.

Transmission Segment Project Commitments: These amounts primarily represent commitments for various services and materials associated with the NEEWS 115 kilovolt (KV) and 345 KV Overhead projects and the final closeout of CL&P's Middletown to Norwalk, Glenbrook Cables and Long Island Replacement project. 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, YAEC and MYAPC.

See Note 7E, "Commitments and Contingencies - Deferred Contractual Obligations," to the consolidated financial statements for information regarding the collection of the Yankee Companies' decommissioning costs.

Clean Air Project Commitments: These amounts represent commitments for engineering, program management services and major component supply and installation 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 SO2 emissions at Merrimack Station Units 1 and 2. The total cost under these contracts amounted to $20.5 million in 2008, $1.9 million in 2007 and $0.9 million in 2006.

Vehicle/Equipment Commitments: The regulated companies have remaining obligations under master lease agreements that were terminated by the lessor in November 2008. As a result of the termination, in accordance with the lease agreements, remaining vehicle/equipment balances of $45 million are required to be paid by January 2011. At the end of the lease, the lessee company will either purchase the vehicle/equipment or sell it at auction with the balances paid to the lessor.

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)	2009	2010	2011	2012	2013	Thereafter	Totals
Select Energy purchase agreements	$40.3	$41.9	$42.9	$38.8	$44.7	$-	$208.6

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.

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 decommissioning and plant closure cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear 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.

NU's percentage share of the obligation to support the Yankee Companies under FERC-approved rate tariffs is the same as the ownership percentages. For further information on the ownership percentages, see Note 1J, "Summary of Significant Accounting Policies - Equity Method Investments," to the consolidated financial statements.

CYAPC, YAEC and MYAPC are currently collecting amounts that NU believes are adequate to recover the remaining decommissioning and closure cost estimates for the respective plants. NU believes CL&P and WMECO will recover their shares of these decommissioning and closure obligations from their customers. 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 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. In December 2007, the Yankee Companies filed lawsuits against the DOE seeking recovery of actual damages incurred in the years following 2001/2002.

In December 2006, the DOE appealed the ruling, and the Yankee Companies filed a cross-appeal. The Court of Appeals issued its decision on August 7, 2008, effectively agreeing with the trial court's findings as to the liability of the DOE but disagreeing with the method that the trial court used to calculate damages. The Court of Appeals vacated the decision and remanded the case for new findings consistent with its decision.

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. 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. Guarantees and Indemnifications

NU provides credit assurances on behalf of subsidiaries in the form of guarantees and 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, NU Enterprises' retail marketing business and its competitive generation business. The following table summarizes NU and its subsidiaries' maximum exposure at December 31, 2008, 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)
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 [2]	Not Specified [1]	Through project completion
	Indemnifications to lenders for payment of shortfalls in the event of early termination of government contracts [3]	$1.3	2017-2018
	Surety bonds covering certain projects	$10.5	Through project completion
Hess Corporation (Retail Marketing Business)	General indemnifications in connection with the sale including compliance with laws, completeness and accuracy of information provided and various claims	Not Specified [1]	None
Energy Capital Partners (Competitive Generation Business)	General indemnifications in connection with the sale of NGC and the generating assets of Mt. Tom including compliance with tax and environmental laws, and various claims	Not Specified [1]	2008-2009
On behalf of subsidiaries:			
CL&P	Surety bonds [4]	$3.2	2009-2010
PSNH	Surety bonds [4]	$3.9	2009-2010
	Letters of credit	$85.0	2009-2010
WMECO	Surety bonds [4]	$3.0	2009
HWP	Surety bonds [4]	$1.0	2009
NAESCO	Surety bonds [4]	$1.6	2009
RRR	Lease payments for real estate	$9.2	2024
NUSCO	Surety bonds [4]	$1.0	2009
	Lease payments for fleet of vehicles	$8.0	None
	Lease payments for real estate	$1.8	2019
Boulos	Surety bonds covering ongoing projects	$34.1	Through project completion
NGS	Performance guarantee and insurance bonds	$20.4[5]	2020 [5]
Select Energy	Performance guarantees and surety bonds for retail marketing contracts	$3.3[6]	None [7]
	Performance guarantees for wholesale contracts	$17.1[6]	2013
	Letters of credit	$2.0	2009
Other - CYAPC	Surety bonds [4]	$0.3	2010

Refer to footnotes on following page.

(1) There is no specified maximum exposure included in the related sale agreements.

(2) The fair value for amounts recorded for these indemnifications was $0.2 million at December 31, 2008.

(3) The fair value for amounts recorded for these indemnifications was $0.1 million at December 31, 2008.

(4) Surety bond expiration dates reflect bond termination dates (which may be renewed or extended) for specified term bonds and/or bill-to dates for bonds with no fixed term.

(5) Included in the maximum exposure is $19.2 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, 2008 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 that are billed annually on their anniversary date.

(6) Maximum exposure is as of December 31, 2008; however, exposures vary with underlying commodity prices and for certain contracts are essentially unlimited.

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

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.

G. 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, among other things now resolved, relate to the recovery of approximately $30.2 million of CL&P's station service billings from NRG, and 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 February 15, 2008, CL&P and NRG, as well as Yankee Gas and NRG, entered into settlement agreements with respect to the two matters mentioned above. The settlements were contingent upon the satisfaction of several conditions related to NRG's RNS service through the ISO-NE, which were materially satisfied in May 2008. The settlement did not have an adverse effect on NU's consolidated net income, financial position or cash flows in 2008.

H. Consolidated Edison, Inc. Merger Litigation

On March 13, 2008, NU entered into a settlement agreement with Consolidated Edison, Inc. (Con Edison), which settled all claims under the civil lawsuit between NU and Con Edison relating to their proposed but unconsummated merger. Under the terms of the settlement agreement, NU paid Con Edison $49.5 million on March 26, 2008, which is included in other operating expenses in the accompanying consolidated statement of income for the year ended December 31, 2008. This amount is not recoverable from ratepayers.

I. 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, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its 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.

8. 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.

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of NU's fixed-rate securities is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions. 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:

	At December 31,			
	2008		2007	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock not subject to mandatory redemption	$ 116.2	$ 86.3	$ 116.2	$ 88.2
Long-term debt -				
First mortgage bonds	2,312.0	2,399.4	1,806.3	1,792.4
Other long-term debt	1,829.5	1,690.6	1,832.3	1,867.4
Rate reduction bonds	686.5	689.4	917.4	975.2

Other long-term debt includes $298.6 million and $294.3 million of fees and interest due for spent nuclear fuel disposal costs at December 31, 2008 and 2007, respectively.

Derivative Instruments: NU and its subsidiaries hold various derivative instruments that are carried at fair value. For further information, see Note 3, "Derivative Instruments," to the consolidated financial statements.

Other Financial Instruments: NU holds investments in a supplemental benefit trust for the benefit of the SERP and non-SERP obligation and investments in the spent nuclear fuel trust for the benefit of WMECO's spent nuclear fuel obligation. These investments are carried at fair value in the accompanying consolidated balance sheets. For further information regarding these investments, see Note 1U, "Summary of Significant Accounting Policies-Marketable Securities," Note 1F, "Summary of Significant Accounting Policies-Fair Value Measurements," and Note 9, "Marketable Securities," to the consolidated financial statements.

NU parent holds a long-term government receivable related to SESI, a former subsidiary that has been sold. The carrying value of the receivable was $8.8 million at both December 31, 2008 and 2007 and is included in other deferred debits and other assets-other on the accompanying consolidated balance sheets. The fair value of this receivable was $11.5 million and $10.8 million at December 31, 2008 and 2007, respectively, and was determined based on discounted cash flows.

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.

9. Marketable Securities

The following is a summary of NU's available-for-sale securities related to the supplemental benefit trust and 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.

	At December 31,	
(Millions of Dollars)	2008	2007
Supplemental benefit trust	$ 53.5	$ 68.4
Spent nuclear fuel trust	55.7	55.7
Totals	$109.2	$124.1

At December 31, 2008 and 2007, marketable securities are comprised of the following:

	At December 31, 2008		
(Millions of Dollars)	Amortized Cost[1]	Pre-Tax Gross Unrealized Gains	Estimated Fair Value
Supplemental benefit trust			
United States equity securities	$ 21.9	$1.1	$ 23.0
Non-United States equity securities	5.6	-	5.6
U.S. government issued debt securities (Agency and Treasury)	13.1	0.8	13.9
Corporate debt securities	3.3	0.2	3.5
Asset backed securities	3.4	-	3.4
Other	4.1	-	4.1
Total supplemental benefit trust	$ 51.4	$2.1	$ 53.5
Spent nuclear fuel trust			
Short-term investments and money markets	$ 16.3	$ -	$ 16.3
U.S. government issued debt securities (Agency and Treasury)	15.4	0.1	15.5
Corporate debt securities	17.4	0.5	17.9
Asset backed securities	2.4	-	2.4
Other	3.6	-	3.6
Total spent nuclear fuel trust	$ 55.1	$0.6	$ 55.7
Total	$106.5	$2.7	$109.2

	At December 31, 2007		
(Millions of Dollars)	Amortized Cost[1]	Pre-Tax Gross Unrealized Gains	Estimated Fair Value
Supplemental benefit trust			
United States equity securities	$ 23.5	$4.3	$ 27.8
Non-United States equity securities	8.3	-	8.3
U.S. government issued debt securities (Agency and Treasury)	14.2	0.3	14.5
Corporate debt securities	6.4	0.1	6.5
Asset backed securities	6.3	-	6.3
Other	5.0	-	5.0
Total supplemental benefit trust	$ 63.7	$4.7	$ 68.4
Spent nuclear fuel trust			
Short-term investments and money markets	$ 14.1	$ -	$ 14.1
U.S. government issued debt securities (Agency and Treasury)	0.7	-	0.7
Corporate debt securities	29.2	-	29.2
Asset backed securities	9.2	0.1	9.3
Other	2.4	-	2.4
Total spent nuclear fuel trust	$ 55.6	$0.1	$ 55.7
Total	$119.3	$4.8	$124.1

(1) Amortized cost amounts are net of unrealized losses that are recorded as other than temporary impairments.

For the years ended December 31, 2008 and 2007, NU recorded pre-tax charges of $15.3 million and $1.9 million, respectively, related to the unrealized losses on securities in the supplemental benefit trust portfolio, and $2.1 million and $0.6 million, respectively, offset to the spent nuclear fuel obligation in long-term debt related to the unrealized losses on securities in the spent nuclear fuel trust. Unrealized losses are considered other than temporary in nature because they are held in trusts and NU does not have the ability to hold these securities to maturity.

For information related to the change in unrealized gains included in accumulated other comprehensive income, see Note 13, "Accumulated Other Comprehensive Income/(Loss)," to the consolidated financial statements.

For the years ended December 31, 2008, 2007 and 2006, 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
2008	$2.5	$(2.2)	$0.3
2007	2.8	(1.0)	1.8
2006	5.2	(1.3)	3.9

The spent nuclear fuel trust net realized losses of $0.4 million and $0.3 million for the years ended December 31, 2008 and 2006, respectively, offset the spent nuclear fuel obligation in long-term debt. For the years ended December 31, 2008, 2007 and 2006, all other net realized gains totaling $0.7 million, $1.9 million and $4.2 million, respectively, are included in other income, net on the accompanying consolidated statements of income. Included in the realized gain/(losses) is a pre-tax gain of $3.1 million for the

year ended December 31, 2006 related to NU's investment in Globix Corporation (Globix), which was sold on April 6, 2006.

NU utilizes the specific identification basis method for the supplemental benefit trust securities and the average cost basis method for the 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 $259.4 million, $254.8 million and $193.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

At December 31, 2008, the contractual maturities of the available-for-sale securities are as follows:

(Millions of Dollars)	Amortized Cost	Estimated Fair Value
Less than one year	$ 49.2	$ 49.9
One to five years	11.9	12.0
Six to ten years	4.3	4.5
Greater than ten years	13.6	14.2
Subtotal	79.0	80.6
Equity securities	27.5	28.6
Total	$106.5	$109.2

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

10. 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 $2.5 million in 2008, $2.9 million in 2007, and $3.3 million in 2006. Interest included in capital lease rental payments was $1.8 million in 2008, $2 million in 2007, and $1.9 million in 2006. Capital lease asset amortization was $0.7 million in 2008, and $0.9 million in both 2007 and 2006.

Operating lease rental payments charged to expense were $19.1 million, $19.6 million and $10.9 million in 2008, 2007 and 2006, respectively. The 2006 amount includes $0.7 million included in income from discontinued operations on the accompanying consolidated statements of income. The capitalized portion of operating lease payments was approximately $10.8 million, $10.5 million and $10 million for the years ended December 31, 2008, 2007 and 2006, 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, 2008 are as follows:

Capital Leases
(Millions of Dollars)

2009	$ 2.4
2010	2.4
2011	2.5
2012	2.6
2013	2.4
Thereafter	15.5
Future minimum lease payments	$27.8
Less amount representing interest	14.4
Present value of future minimum lease payments	$13.4

Operating Leases
(Millions of Dollars)

2009	$24.6
2010	18.9
2011	7.1
2012	6.1
2013	5.9
Thereafter	23.9
Future minimum lease payments	$86.5

In November 2008, the lessor of NU's vehicle/equipment master lease agreements notified the company that it was electing to terminate the lease agreements as permitted under the termination clause of the agreements. The remaining payments under the agreements will be made through January 2011. See Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," for obligations relating to the termination.

CL&P entered into certain contracts for the purchase of energy that qualify as leases under 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 tables above. See Note 7D, "Commitments and Contingencies - Long-Term Contractual Arrangements," for further information regarding these contracts.

11. Long-Term Debt

Long-term debt maturities and cash sinking fund requirements on debt outstanding at December 31, 2008, for the years 2009 through 2013 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, 2008, are as follows:

(Millions of Dollars)	
2009	$ 54.3
2010	4.3
2011	4.3
2012	267.3
2013	305.0
Thereafter	3,207.8
Fees and interest due for spent nuclear fuel disposal costs	298.6
Net unamortized premiums and discounts and other fair value adjustments	15.9
Total	$ 4,157.5

There are annual renewal and replacement fund requirements equal to 2.25 percent of the average of net depreciable utility property owned by PSNH in 1992, plus cumulative gross property additions thereafter. PSNH expects to meet these future fund requirements by certifying property additions. Any deficiency would need to be satisfied by the deposit of cash or bonds.

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.

NU and its subsidiaries' tax-exempt bonds contain call provisions ranging between 100 percent and 102 percent of par. All other securities are subject to make-whole provisions.

CL&P has $423.9 million of tax-exempt Pollution Control Revenue Bonds (PCRBs), $315.5 million of which is secured by second mortgage liens on transmission assets, junior to the liens of its first mortgage bond indentures and the remaining $108.4 million of which is secured by its first mortgage bonds. One series of PCRBs, in the aggregate principal amount of $62 million, had a fixed interest rate for a five-year period that expired on September 30, 2008. As a result of poor liquidity in the tax-exempt market, CL&P chose to acquire this series of PCRBs on October 1, 2008. These PCRBs, which mature in 2031, have not been retired and are temporarily held by CL&P in a flexible rate mode with one day resets.

At December 31, 2008 PSNH had $407.3 million in outstanding PCRBs. PSNH's obligation to repay each series of PCRBs is secured by first mortgage bonds and three series, the 2001 Series A, B and C, also carry bond insurance. 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. The 2001 Series B PCRBs, in the aggregate principal amount of $89.3 million, bears interest at a rate that is periodically set pursuant to auctions. Since March 2008, a significant majority of this

series of PCRBs has been held by remarketing agents as a result of failed auctions due to general market concerns. The interest rate on these PCRBs has been reset by formula under the applicable documents every 35 days and has been between 0.4 percent and 4 percent since March 2008. The formula is based on a combination of the ratings on the PCRBs and an index rate, which provides for an interest rate of 0.4 percent as of December 31, 2008. The company is not obligated to purchase these PCRBs, which mature in 2021, from the remarketing agents.

NU and its subsidiaries' 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 a consolidated debt to capitalization ratio. These subsidiaries are in compliance with these covenants at December 31, 2008.

Yankee Gas has certain long-term debt agreements that contain cross-default provisions that would be triggered if Yankee Gas or any subsidiary default in a payment in excess of a predetermined amount. These cross-default provisions apply to Yankee Gas' Series B and Series E through J debt issuances. PSNH would also be in default under its long-term debt agreements if it defaulted on any prior lien obligation exceeding $25 million. PSNH has no prior lien obligations as of December 31, 2008. There are no other debt issuances for NU and its subsidiaries with cross-default provisions at December 31, 2008.

The weighted average effective interest rate on PSNH's Series A variable-rate PCRBs was 3.07 percent for 2008 and 3.87 percent for 2007. The CL&P PCRB due in 2031 had an interest rate of 3.35 percent effective through October 1, 2008, at which time the bonds were reacquired by CL&P and are now in a daily variable interest rate mode.

Long-term debt - First Mortgage Bonds on the accompanying consolidated statements of capitalization at December 31, 2008 includes the issuance of $300 million and $110 million at CL&P and PSNH, respectively.

Other long-term debt - other on the accompanying consolidated statements of capitalization at December 31, 2008 includes a senior unsecured note issuance of $250 million at NU parent, due 2013 with a coupon of 5.65 percent and the issuance of $100 million in Series J First Mortgage Bonds at Yankee Gas, due 2018 with a coupon of 6.9 percent.

For information regarding fees and interest due for spent nuclear fuel disposal costs, see Note 7C, "Commitments and Contingencies - Spent Nuclear Fuel Disposal Costs," to the consolidated financial statements.

The change in fair value totaling a positive $20.8 million and $4.2 million at December 31, 2008 and 2007, 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.

12. Dividend Restrictions

NU parent'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 consolidated total debt to total capitalization ratio requirement in its revolving credit agreement, and the ability of NU's subsidiaries to pay common dividends to it.

CL&P, PSNH, and WMECO are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, PSNH and WMECO, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from retained earnings. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas. Such state law restrictions do not restrict payment of dividends from retained earnings or net income. CL&P, PSNH, WMECO and Yankee Gas also have a revolving credit agreement that imposes leverage restrictions including consolidated total debt to total capitalization ratio requirements. The retained earnings balance subject to these leverage restrictions is $1.079 billion for NU consolidated. PSNH is further required to reserve an additional amount under its FERC hydroelectric license conditions. Approximately $11 million of PSNH's retained earnings is subject to restriction under its FERC hydroelectric license conditions. At December 31, 2008, NU was in compliance with all such provisions of its credit agreement that may restrict the payment of dividends.

13. 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	2007 Change	December 31, 2007	2008 Change	December 31, 2008
Qualified cash flow hedging instruments	$5.9	$ (3.6)	$2.3	$ (6.9)	$ (4.6)
Unrealized gains on securities	3.0	(0.1)	2.9	(1.7)	1.2
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	(4.4)	8.6	4.2	(38.1)	(33.9)
Accumulated other comprehensive income/(loss)	$4.5	$ 4.9	$9.4	$(46.7)	$(37.3)

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

(Millions of Dollars)	2008	2007	2006
Qualified cash flow hedging instruments	$ 4.5	$ 2.5	$ 6.9
Unrealized gains on securities	1.1	0.1	(0.5)
Minimum SERP liability	-	-	(0.3)
Pension, SERP and other postretirement plans benefit obligations (SFAS No. 158)	24.2	(9.8)	6.1
Accumulated other comprehensive income/(loss)	$29.8	$(7.2)	$12.2

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

	At December 31,	
(Millions of Dollars, Net of Tax)	2008	2007
Balance at beginning of year	$ 2.3	$5.9
Hedged transactions recognized into earnings	0.4	0.2
Change in fair value of interest rate swap agreements	(7.0)	-
Cash flow transactions entered into for period	(0.3)	(3.8)
Net change associated with hedging transactions	(6.9)	(3.6)
Total fair value adjustments included in accumulated other comprehensive income	$(4.6)	$2.3

Hedged transactions recognized into earnings in the table on the previous page represent amounts that were 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. These amounts are net of income taxes of approximately $0.2 million for the year ended December 31, 2008.

The following table provides the forward starting interest rate swap transactions entered into by the company, CL&P, PSNH, WMECO and Yankee Gas to hedge interest rate risk associated with their respective long-term debt issuances in 2008 and 2007:

	2008				2007		
	NU parent	CL&P	PSNH	Yankee Gas	CL&P	CL&P	WMECO
Long-term debt issued (in millions)	$250	$300	$110	$100	$150 and $150	$100 and $100	$40
Date entered into swap transaction	12/3/07	12/5/07	12/4/07	12/4/07	2/22/07	7/16/07	7/17/07
Term	5-year	10-year	10-year	10-year	10-year and 30-year	10-year and 30-year	30-year
Termination date	6/2/08	5/19/08	3/24/08[3]	9/23/08[4]	3/27/07	9/10/07	8/15/07
Loaded LIBOR swap percentage rate(s) (percentage)	4.102[1]	4.590 and 4.602[2]	4.5575 and 4.147[3]	4.635 and 4.5685[4]	5.229 and 5.369[7]	5.718 and 5.865[9]	5.882
Charge to accumulated other comprehensive income (net of tax)[5]	$0.1	$2.3	$0.9[6]	$0.7	$1.6	$4.7[8]	$0.6

(1) The interest rate swap was entered into with a notional amount of $200 million and had a positive fair value of $0.6 million at December 31, 2007.

(2) The two locked rates reflect two forward starting interest rate swap transactions, each with a notional amount of $150 million and were recorded at a fair value of a positive $1.4 million at December 2007.

(3) The first swap transaction had a fair value of a positive $0.6 million at December 31, 2007. This swap was replaced at its scheduled termination date on March 24, 2008 with a new swap to extend the hedging relationship to the revised pricing date of the long-term debt to May 19, 2008.

(4) The first swap transaction had a positive fair value of $0.5 million at December 31, 2007 and was replaced at its scheduled termination date of September 23, 2008 with a new swap to extend the hedging relationship to the revised pricing date of the long-term debt on October 7, 2008. On September 26, 2008, the debt was priced and the second swap was unwound.

(5) The charge to accumulated other comprehensive income will be amortized into earnings over the terms of each respective long-term debt.

(6) The amount charged to accumulated other comprehensive income is net of ineffectiveness of $0.2 million related to the settlement of the March 2008 forward starting swap agreement.

(7) The two locked rates reflect two forward starting interest rate swap transactions, each with a notional amount of $75 million.

(8) The amount charged to accumulated other comprehensive income is net of ineffectiveness of $67 thousand incurred upon termination of the hedge.

(9) The two locked rates reflect two forward starting interest rate swap transactions, each with a notional amount of $50 million.

It is estimated that a charge of $0.2 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. At December 31, 2008, it is estimated that a pre-tax amount of $0.7 million included in the accumulated other comprehensive income balance will be reclassified as a decrease to earnings over the next 12 months related to Pension, SERP and other postretirement benefits adjustments.

14. Restructuring and Impairment Charges and Discontinued Operations

Restructuring and Impairment Charges: NU Enterprises recorded $0.2 million and $27.6 million of pre-tax restructuring and impairment charges for the years ended December 31, 2007 and 2006, respectively, relating to the decision to exit NU Enterprises. There were no restructuring and impairment charges recorded in 2008. These charges are included as part of the NU Enterprises reportable segment in Note 16, "Segment Information," to the consolidated financial statements.

In 2006, $22.7 million of restructuring charges and $0.3 million of impairment charges were recorded related to Select Energy's wholesale marketing, retail marketing and competitive generation businesses. The restructuring charges were recorded for consulting fees, legal fees, sale-related environmental fees and employee related and other costs. The impairment costs related to the divestiture of the competitive generation business. In addition, $4.6 million of restructuring charges were recorded related to the remaining services businesses. Included in this amount are restructuring charges of $1 million related to the termination of NU parent's guarantee of SESI's performance under government contracts. Of these amounts $19.1 million are included in discontinued operations and $8.5 million are included as other operating expenses. In 2007, $0.2 million of restructuring charges were recorded relating to the remaining services businesses.

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 and 2008	$ -	$ 0.3	$ 0.3

Discontinued Operations: NU's consolidated statements of income for the years ended December 31, 2007 and 2006 present NGC, Mt. Tom, SESI, Woods Electrical and SECI as discontinued operations. Under discontinued operations presentation, revenues and expenses of the businesses classified as discontinued operations are classified in income from discontinued operations on the accompanying consolidated statements of income.

Summarized financial information for the discontinued operations is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2008	2007	2006
Operating revenue	$-	$1.3	$180.7
Income before income taxes	-	0.4	31.3
Gains from sale/disposition of discontinued operations	-	2.1	504.3
Income tax expense	-	1.9	198.0
Net income	-	0.6	337.6

In 2007, gains 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 from 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 accompanying consolidated statement of income.

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 years ended December 31, 2008 or 2007. For the year ended December 31, 2006, included in discontinued operations are $161 million of intercompany revenues that are not eliminated in consolidation due to the separate presentation of discontinued operations. Of this amount, $160.7 million represents 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, 2008, NU did not have or expect to have significant ongoing involvement or continuing cash flows with the entities presented in discontinued operations.

15. 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, 2,500 options were excluded from the following table as these options were antidilutive. In 2008 and 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)	2008	2007	2006
Income from continuing operations	$260.8	$245.9	$132.9
Income from discontinued operations	-	0.6	337.7
Net income	$260.8	$246.5	$470.6
Basic common shares outstanding (average)	155,531,846	154,759,727	153,767,527
Dilutive effect	467,394	544,634	379,142
Fully diluted common shares outstanding (average)	155,999,240	155,304,361	154,146,669
Basic EPS:			
Income from continuing operations	$1.68	$1.59	$0.86
Income from discontinued operations	-	-	2.20
Net income	$1.68	$1.59	$3.06
Fully Diluted EPS:			
Income from continuing operations	$1.67	$1.59	$0.86
Income from discontinued operations	-	-	2.19
Net income	$1.67	$1.59	$3.05

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 related to equity funds, and the capitalized portions of pension and PBOP 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 segments, including the electric distribution and transmission segments, as well as the gas distribution segment (Yankee Gas), represented approximately 99 percent, 99 percent and 87 percent of NU's total consolidated revenues for the years ended December 31, 2008, 2007 and 2006, respectively.

The NU Enterprises segment is comprised of the following: 1) Select Energy (wholesale contracts), 2) Boulos, 3) NGS, 4) NGS Mechanical, 5) SECI, and 6) 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 RRR and the Quinnehtuk Company (real estate subsidiaries), Mode 1 Communications, Inc. and the results of the non-energy-related subsidiaries of Yankee (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 years ended December 31, 2008 and 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, 2008, 2007 and 2006.

NU's consolidated statements of income for the years ended December 31, 2007 and 2006 present the operations for NGC, including certain components of NGS, Mt. Tom, SESI, a portion of the former Woods Electrical and SECI as discontinued operations. For further information and information regarding the exit from these businesses, see Note 14, "Restructuring and Impairment Charges and Discontinued Operations," to the consolidated financial statements.

Intercompany Transactions: Total Select Energy revenues from CL&P represented approximately $6.1 million of total NU Enterprises' revenues for the year ended December 31, 2006. Total CL&P purchases from Select Energy related to nontraditional standard offer contracts are eliminated in consolidation. There were no such transactions in 2008 or 2007.

Select Energy purchases from NGC and Mt. Tom represented $160.7 million through November 1, 2006, at which time NU completed the sale of its 100 percent ownership in NGC stock and Mt. Tom.

Customer Concentrations: 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 and $404.4 million for the years ended December 31, 2007 and 2006, 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, 2008, 2007 and 2006. 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, 2008, 2007 and 2006 is as follows (some amounts may not agree between the financial statements and the segment schedules due to rounding):

	Regulated Companies						
	Distribution[1]						
(Millions of Dollars)	Electric	Gas	Transmission	NU Enterprises	Other	Eliminations	Total
For the Year Ended December 31, 2008							
Operating revenues	$ 4,716.1	$ 577.4	$ 424.8	$ 114.1	$ 416.6	$ (448.9)	$ 5,800.1
Depreciation and amortization	(581.5)	(26.2)	(49.3)	(0.6)	(13.1)	0.9	(669.8)
Other operating expenses	(3,828.6)	(487.3)	(138.5)	(89.6)	(431.2)	435.7	(4,539.5)
Operating income/(loss)	306.0	63.9	237.0	23.9	(27.7)	(12.3)	590.8
Interest expense, net of AFUDC	(164.3)	(21.6)	(51.8)	(5.6)	(35.4)	9.6	(269.1)
Interest income	14.1	0.5	2.1	1.0	8.5	(10.6)	15.6
Other income, net	13.1	0.3	21.8	-	227.5	(227.9)	34.8
Income tax (expense)/benefit	(41.6)	(16.0)	(68.8)	(6.2)	28.7	(1.8)	(105.7)
Preferred dividends	(3.6)	-	(2.0)	-	-	-	(5.6)
Net income	$ 123.7	$ 27.1	$ 138.3	$ 13.1	$ 201.6	$ (243.0)	$ 260.8
Total assets[2]	$11,968.0	$1,424.8	$ -	$ 85.2	$ 5,060.1	$(4,549.6)	$13,988.5
Cash flows for total investments in plant[3]	$ 487.8	$ 58.4	$ 678.9	$ -	$ 30.3	$ -	$ 1,255.4
For the Year Ended December 31, 2007							
Operating revenues	$ 4,930.8	$ 514.1	$ 298.7	$ 97.7	$ 389.8	$ (408.9)	$ 5,822.2
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)	(77.9)	(358.3)	405.6	(4,775.7)
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							
Operating revenues	$ 5,336.0	$ 453.9	$ 216.0	$ 901.8	$ 355.0	$ (385.0)	$ 6,877.7
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)	(1,076.8)	(335.9)	363.2	(6,196.6)
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
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, 2008 and 2007. 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 related to equity funds, and the capitalized portions of pension and PBOP expense or income.

17. Subsequent Event

On February 13, 2009, CL&P issued $250 million of Series A first and refunding mortgage bonds with a coupon rate of 5.5 percent and a maturity date of February 1, 2019. The proceeds from this issuance will be used to repay short-term debt and to fund CL&P's ongoing capital investment programs.

CONSOLIDATED STATEMENTS OF QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarter Ended (a)			
(Thousands of Dollars, except per share information)	**March 31,**	**June 30,**	**September 30,**	**December 31,**
2008				
Operating Revenues	$ 1,519,967	$ 1,325,345	$1,506,897	$ 1,447,886
Operating Income	132,272	138,119	149,077	171,297
Net Income	58,393	57,848	72,689	71,898
Basic and Fully Diluted Earnings Per Common Share	$ 0.38	$ 0.37	$ 0.47	$ 0.46
2007				
Operating Revenues	$ 1,703,518	$ 1,391,772	$1,450,977	$ 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 and Fully Diluted 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

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

SELECTED CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(Thousands of Dollars, except percentages and share information)	2008	2007	2006	2005	2004
Balance Sheet Data:					
Property, Plant and Equipment, Net	$ 8,207,876	$ 7,229,945	$ 6,242,186	$ 6,417,230	$ 5,864,161
Total Assets	13,988,480	11,581,822	11,303,236	12,567,875	11,638,396
Total Capitalization (a)	7,293,960	6,667,920	5,879,691	5,595,405	5,293,644
Obligations Under Capital Leases (a)	13,397	14,743	14,425	13,987	14,806
Income Data:					
Operating Revenues	$ 5,800,095	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684
Income/(Loss) from Continuing Operations	260,828	245,896	132,936	(256,903)	70,423
Income from Discontinued Operations	-	587	337,642	4,420	46,165
Income/(Loss) Before Cumulative Effects of Accounting Changes, Net of Tax Benefits	260,828	246,483	470,578	(252,483)	116,588
Cumulative Effects of Accounting Changes, Net of Tax Benefits	-	-	-	(1,005)	-
Net Income/(Loss)	$ 260,828	$ 246,483	$ 470,578	$ (253,488)	$ 116,588
Common Share Data:					
Basic Earnings/(Loss) Per Common Share:					
Income/(Loss) from Continuing Operations	$ 1.68	$ 1.59	$ 0.86	$ (1.95)	$ 0.55
Income from Discontinued Operations	-	-	2.20	0.03	0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits	-	-	-	(0.01)	-
Net Income/(Loss)	$ 1.68	$ 1.59	$ 3.06	$ (1.93)	$ 0.91
Fully Diluted Earnings/(Loss) Per Common Share:					
Income/(Loss) from Continuing Operations	$ 1.67	$ 1.59	$ 0.86	$ (1.95)	$ 0.55
Income from Discontinued Operations	-	-	2.19	0.03	0.36
Cumulative Effects of Accounting Changes, Net of Tax Benefits	-	-	-	(0.01)	-
Net Income/(Loss)	$ 1.67	$ 1.59	$ 3.05	$ (1.93)	$ 0.91
Basic Common Shares Outstanding (Average)	155,531,846	154,759,727	153,767,527	131,638,953	128,245,860
Fully Diluted Common Shares Outstanding (Average)	155,999,240	155,304,361	154,146,669	131,638,953	128,396,076
Dividends Per Share	$ 0.83	$ 0.78	$ 0.73	$ 0.68	$ 0.63
Market Price - Closing (high) (b)	$ 31.15	$ 33.53	$ 28.81	$ 21.79	$ 20.10
Market Price - Closing (low) (b)	$ 19.15	$ 26.93	$ 19.24	$ 17.61	$ 17.30
Market Price - Closing (end of year) (b)	$ 24.06	$ 31.31	$ 28.16	$ 19.69	$ 18.85
Book Value Per Share (end of year)	$ 19.38	$ 18.79	$ 18.14	$ 15.85	$ 17.80
Tangible Book Value Per Share (end of year)	$ 17.54	$ 16.93	$ 16.28	$ 13.98	$ 15.17
Rate of Return Earned on Average Common Equity (%)	8.8	8.6	18.0	(10.7)	5.1
Market-to-Book Ratio (end of year)	1.2	1.7	1.6	1.2	1.1
Capitalization:					
Common Shareholders' Equity	41%	44%	48%	43%	44%
Preferred Stock	2	2	2	2	2
Long-Term Debt (a)	57	54	50	55	54
	100%	100%	100%	100%	100%

(a) Includes portions due within one year, but excludes RRBs.

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

SELECTED CONSOLIDATED SALES STATISTICS (UNAUDITED)

	2008	2007	2006	2005	2004
Revenues: ***(Thousands)***					
Regulated companies:					
Residential	$ 2,525,635	$ 2,558,547	$ 2,409,414	$ 2,080,395	$ 1,707,434
Commercial	1,607,224	1,735,923	1,977,444	1,727,278	1,429,608
Industrial	399,753	412,381	589,742	577,834	513,999
Wholesale	545,127	392,675	388,635	411,361	344,254
Streetlighting and Railroads	38,522	45,880	52,853	47,769	41,976
Miscellaneous and eliminations	24,673	84,043	133,925	159,402	143,431
Total Electric	5,140,934	5,229,449	5,552,013	5,004,039	4,180,702
Total Gas	577,390	514,185	453,894	503,303	407,812
Total - Regulated companies	$ 5,718,324	$ 5,743,634	$ 6,005,907	$ 5,507,342	$ 4,588,514
NU Enterprises:					
Retail	$ -	$ -	$ 583,829	$ 1,212,176	$ 857,355
Wholesale	31,882	25,992	20,163	644,541	1,722,603
Generation	-	-	258,178	210,833	196,191
Services	78,625	68,324	39,887	102,327	117,500
Miscellaneous and eliminations	3,574	3,354	(243)	(257,750)	(245,745)
Total - NU Enterprises	$ 114,081	$ 97,670	$ 901,814	$ 1,912,127	$ 2,647,904
Other miscellaneous and eliminations	(32,310)	(19,078)	(30,034)	(73,243)	(755,734)
Total	$ 5,800,095	$ 5,822,226	$ 6,877,687	$ 7,346,226	$ 6,480,684
Regulated companies - Sales: (GWH)					
Residential	14,509	15,051	14,652	15,518	14,866
Commercial	14,885	15,103	14,886	15,234	14,710
Industrial	5,149	5,635	5,750	6,023	6,274
Wholesale	3,576	3,855	8,777	4,856	5,787
Streetlighting and Railroads	340	353	332	348	348
Total	38,459	39,997	44,397	41,979	41,985
Regulated companies - Customers: (Average)					
Residential	1,700,207	1,697,073	1,686,169	1,674,563	1,659,419
Commercial	190,067	189,727	188,281	195,844	194,233
Industrial	7,342	7,291	7,406	7,638	7,752
Streetlighting and Railroads	4,605	3,855	3,873	3,912	3,930
Total Electric	1,902,221	1,897,946	1,885,729	1,881,957	1,865,334
Gas	204,834	202,743	199,377	196,870	194,212
Total	2,107,055	2,100,689	2,085,106	2,078,827	2,059,546

trustees and officers
(as of february 27, 2009)

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Secretary, CL&P, PSNH and Yankee Gas and Secretary and Clerk, WMECO

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 28, 2009, there were 43,965 common shareholders of record of Northeast Utilities, holding an aggregate of 156,044,000 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 per Share
2008	First	$ 31.15	$ 24.01	$ 0.20
	Second	$ 27.74	$ 25.12	$ 0.20
	Third	$ 28.03	$ 24.52	$ 0.2125
	Fourth	$ 25.97	$ 19.15	$ 0.2125
2007	First	$ 32.77	$ 27.40	$ 0.1875
	Second	$ 33.53	$ 27.37	$ 0.1875
	Third	$ 29.42	$ 26.93	$ 0.20
	Fourth	$ 32.83	$ 27.98	$ 0.20

Transfer Agent and Registrar
BNY Mellon 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 10:30 a.m. on May 12, 2009, at the Sheraton Springfield Monarch Place Hotel, One Monarch Place, Springfield, MA.

Compliance with New York Stock Exchange Corporate Governance Rules
The company's Annual Report on Form 10-K for 2008 contained the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002, and on June 12, 2008, 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 2008 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, CT 06141-0270

Review Your Annual Report and Proxy Electronically
An option to receive your annual report and proxy materials electronically began in 2005, when 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.

Northeast Utilities is committed to sustainability and protecting the environment. In conducting our business, we:

- maintain compliance with both the letter and spirit of environmental protection laws and our own procedures;
- demonstrate leadership by pursuing economically, socially and environmentally sustainable initiatives that protect the environment and are consistent with our corporate vision;
- ensure the accountability of employees and their openness with and responsiveness to co-workers, customers, shareholders and the public, by establishing specific objectives and measurable targets that promote continuous improvement and by reporting our environmental performance; and
- practice stewardship by managing our operations with genuine care and by working to reduce or eliminate significant environmental impacts and prevent pollution resulting from our activities.

To that end, our 2008 annual report is printed on recycled paper using 100 percent and 30 percent post-consumer waste with soy-based inks.

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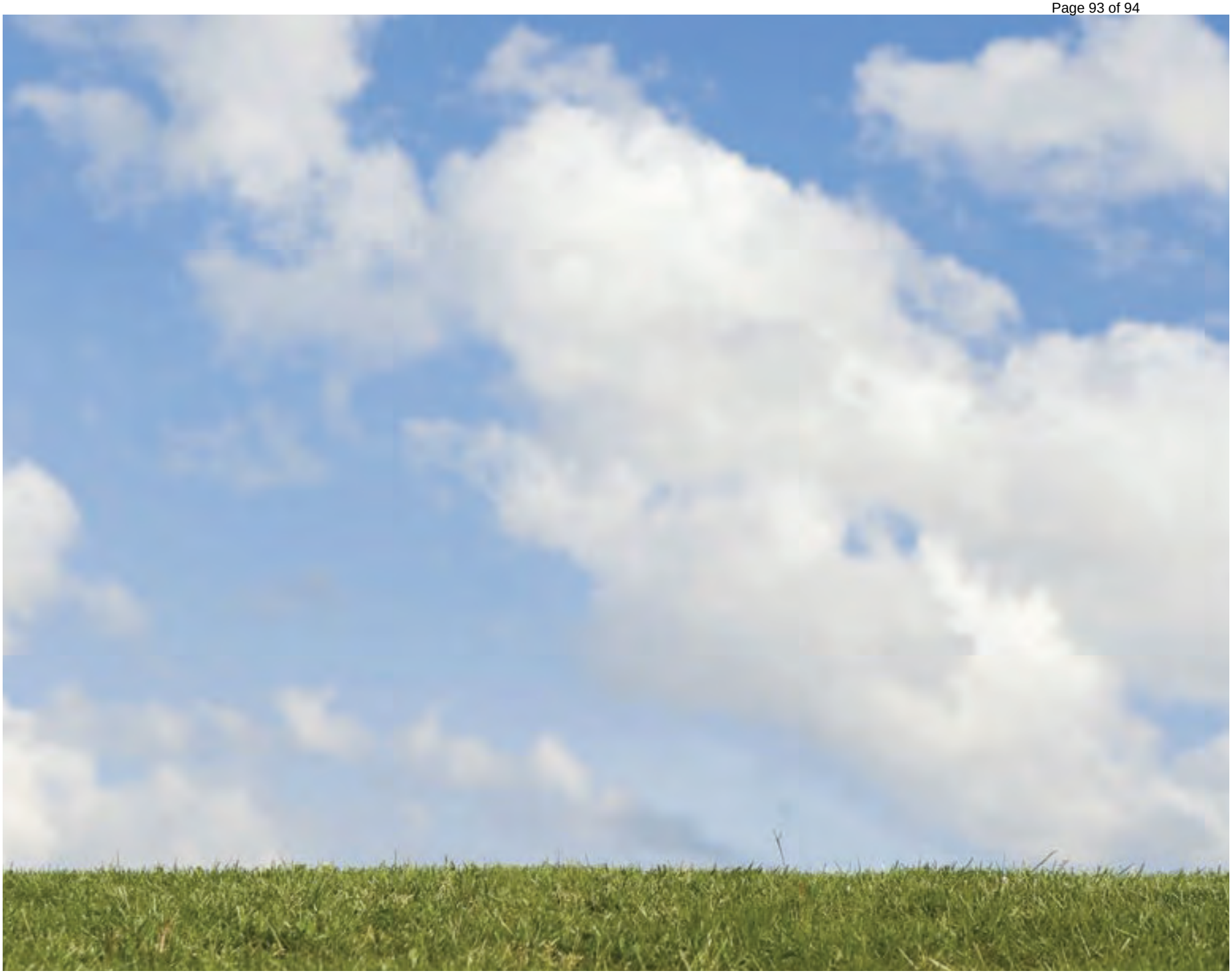

Northeast
Utilities

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